BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2019-185-E
DOCKET NO. 2019-186-E
ORDER NO. 2019-___

NOVEMBER ___, 2019

In the Matter of: South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's and Duke Energy Progress LLC's Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A)	))))))))))))))	DUKE ENERGY CAROLINAS, LLC'S AND DUKE ENERGY PROGRESS LLC'S PROPOSED ORDER APPROVING STANDARD OFFER TARIFFS, AVOIDED COST METHODOLOGIES, FORM CONTRACT POWER PURCHASE AGREEMENTS, AND COMMITMENT TO SELL FORMS

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I. INTRODUCTION AND PROCEDURAL HISTORY

This matter comes before the Public Service Commission of South Carolina (the "Commission" or "PSC") on the Joint Application of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP," together with DEC, the "Companies" or "Duke") for Approval of Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Other Related Terms and Conditions filed August 14, 2019 (the "Joint Application"). The Joint Application requested approval of the Companies' application of the peaker methodology to calculate DEC's and DEP's avoided cost rates, DEC's and DEP's updated Standard Offer available to all qualifying cogenerators and small power production facilities ("QFs") up to 2 megawatts ("MW") in size, DEC's and DEP's form of power purchase agreement available to small power producer QFs that are not eligible for the Standard Offer ("Large QF PPA"), and DEC's and DEP's notice of commitment to sell form ("Notice of Commitment Form"). The Joint Application was filed in Docket Nos. 2019-185-E ("DEC Docket") and 2019-186-E ("DEP Docket," together with the DEC Docket, the "Duke Dockets") pursuant to S.C. Code Ann. § 58-41-20(A) and Commission Order No. 2019-524 to accomplish and further the purposes and goals of the South Carolina Energy Freedom Act ("Act 62" or the "Act").

Along with its Joint Application, on August 14, 2019, Duke filed the direct testimony of George Brown, General Manager of Strategy, Policy, and Strategic Investment in the Distributed Energy Technology group at Duke Energy Corporation ("Duke Energy"); Glen A. Snider, Director of Carolinas Integrated Resource Planning and Analytics for Duke Energy; Steven B. Wheeler, Director of Pricing and Regulatory

Solutions for Duke Energy Business Services, LLC ("DEBS")[1]; David B. Johnson, Director of Business Development and Compliance for Duke Energy, and Nick Wintermantel, Principal Consultant and Partner at Astrapé Consulting. Exhibits were included with the direct testimony of Witnesses Snider, Wheeler, Johnson and Wintermantel. The Commission granted confidential treatment of Snider DEC Exhibit 1 and Snider DEP Exhibit 1 in Order No. 2019-684.

The Companies' most recently approved avoided cost rates and Standard Offer Tariffs, which became effective July 1, 2016, were approved by the Commission in Docket No. 1995-1192-E by Order No. 2016-349. In particular, the Order approved the Companies' offer of variable, 5-year and 10-year term avoided cost rates for QFs up to 2 MW in size.

On July 18, 2019, the Commission Clerk's Office issued the Notice of Filing and Hearing and Prefile Testimony Deadlines (the "Notice") in the Duke Dockets and instructed the Companies to publish it in newspapers of general circulation in the areas affected by the Companies' Joint Application on or before July 29, 2019, and provide Proof of Publication to the Commission by August 12, 2019. On August 9, 2019, DEP filed affidavits with the Commission demonstrating the Notice was duly published in accordance with the Docketing Department's instructions. On August 9, 2019, DEC advised the Commission that due to a "system error," one of the newspapers in the DEC service territory did not publish the Notice by July 29, 2019, but the Notice was subsequently

[1] DEBS provides various administrative and other services to DEC, DEP and other affiliated companies of Duke Energy.

published on August 9, 2019. DEC also provided the affidavits of publication to the Commission in its August 9, 2019 filing.

Johnson Development Associates, Inc. ("Johnson Development"), represented by James H. Goldin, Esquire, Weston Adams, III, Esquire, Jeremy C. Hodges, Esquire and Harold W. Gowdy, Esquire, filed a petition to intervene in the Duke Dockets on June 13, 2019.[2] South Carolina Solar Business Alliance, Inc. ("SCSBA"), represented by Richard L. Whitt, Esquire, Weston Adams, III, Esquire, Jeremy C. Hodges, Esquire and Benjamin L. Snowden, Esquire, filed a petition to intervene in the Duke Dockets on June 14, 2019.[3] Nucor Steel – South Carolina ("Nucor"), represented by Robert R. Smith, II, Esquire, filed a petition to intervene in the DEP Docket on July 3, 2019.[4] The South Carolina Coastal Conservation League and Southern Alliance for Clean Energy ("SACE/CCL"), represented by James Blanding Holman IV, Esquire, Stinson W. Ferguson, Esquire, Lauren Joy Bowmen, Esquire and Maia Danaid Hutt, Esquire filed a petition to intervene in the Duke Dockets on July 12, 2019.[5] Walmart, Inc. ("Walmart"), represented by Stephanie U. Eaton, Esquire, Carrie Harris Grundmann, Esquire, and Derrick Price Williamson, Esquire, filed a petition to intervene in the Duke Dockets on July 30, 2019.[6] The South Carolina Energy Users Committee ("SCEUC"), represented by Scott Elliott, Esquire, filed petitions to intervene on August 7, 2019, in the DEC Docket, and August 12, 2019, in the DEP Docket.[7]

[2] Johnson Development's Petition was granted by Order No. 2019-442 (DEC) and Order No. 2019-443 (DEP).
[3] SCSBA's Petition was granted by Order No. 2019-446 (DEC) and Order No. 2019-447 (DEP).
[4] Nucor's Petition was granted by Order No. 2019-520.
[5] SACE/CCL's Petition was granted by Order No. 2019-544.
[6] Walmart's Petition was granted by Order No. 2019-568.
[7] SCEUC's Petitions were granted by Order No. 2019-587 (DEC) and Order No. 2019-605 (DEP).

Ecoplexus, Inc. ("Ecoplexus"), represented by Richard L. Whitt, Esquire, filed a petition to intervene in the Duke Dockets on August 12, 2019.[8] The South Carolina Department of Consumer Affairs ("Consumer Affairs"), exercising its right to intervene to advocate for the interest of consumers pursuant to S.C. Code Ann. § 37-6-604(C), was represented by Becky Dover, Esquire and Carri Grube-Lybarker, Esquire. The Office of Regulatory Staff ("ORS"), automatically a party pursuant to S.C. Code Ann. § 58-4-10(B), was represented by Andrew M. Bateman, Esquire, Alexander W. Knowles, Esquire and Nanette S. Edwards, Esquire. The Companies were represented by Rebecca J. Dulin, Esquire, Heather Shirley Smith, Esquire, E. Brett Breitschwerdt, Esquire, Frank R. Ellerbe III, Esquire, Samuel J. Wellborn, Esquire and Len S. Anthony, Esquire. Collectively, DEC, DEP, Johnson Development, SCSBA, Nucor, SACE/CCL, Walmart, SCEUC, Ecoplexus, Consumer Affairs and ORS are referred to as the "Parties" or individually as a "Party."

Pursuant to S.C. Code Ann. § 58-41-20(I) by Order No. 2019-621 on August 28, 2019, the Commission appointed John Dalton of Power Advisory, LLC ("Power Advisory") as the independent third-party consultant to advise and report to the Commission on the Companies' avoided costs. In addition to receiving and responding to requests for information and discovery from ORS and intervenors, the Companies received Power Advisory's First Set of Interrogatories and First Requests for Production of Documents on September 12, 2019. The Companies provided initial responsive documents on September 18, 2019, and followed up with the remaining requested documents and information on September 20, 2019. The Companies received Power Advisory's Second

[8] Ecoplexus's Petition was granted by Order No. 2019-613.

Set of Interrogatories on October 2, 2019, and provided responses on October 10, 2019. By Order 2019-107-H, the Commission set a date of November 4, 2019, by which Power Advisory shall provide the Commission and Parties with its Final Report. On November 1, 2019, Power Advisory provided its Final Report to the Commission and Parties. The Parties were to provide comments on the Power Advisory Report by 12:00 p.m. on November 8, 2019. The Companies have provided those comments to the Commission in a separate filing.

As set forth in Order No. 2019-107-H, the Parties filed prehearing briefs on September 30, 2019.[9] In the prehearing briefs, the Parties provided their statement of the case, identified witnesses and provided brief summaries of witness testimony as well as outlined the legal issues before the Commission.[10] On October 8, 2019, the parties filed responsive prehearing briefs in which they provided a summary of their responses to other Parties' positions, outstanding procedural and evidentiary issues, summaries of testimony filed since September 30, 2019, and discussions of any stipulations reached or issues not in controversy.

On September 11, 2019, Johnson Development filed the direct testimony of Rebecca Chilton, an independent consultant doing business as Izuba Consulting. On September 11, 2019, SCSBA filed the direct testimony of Steven J. Levitas, Senior Vice-President for Strategic Initiatives for Pine Gate Renewables, LLC; Hamilton Davis, Director of Regulatory Affairs for Southern Current, LLC; and, Jon Downey, President and

[9] The Prehearing Brief Schedule was originally set in Order Nos. 2019-104-H and 2019-105-H and subsequently clarified and adjusted in Order No. 2019-107-H.
[10] Intervenors Walmart, SCEUC and Nucor submitted letters in lieu of prehearing briefs.

CEO of Southern Current, LLC.[11] Exhibits were included with the direct testimony of Levitas. On September 12, 2019, SCSBA filed the direct testimony and exhibits of Ed Burgess, Senior Director at Strategen Consulting.[12] SCSBA filed amended direct testimony of Witness Burgess on October 17, 2019. On September 11, 2019, SACE/CCL filed the direct testimony and exhibits of James F. Wilson, an independent consultant and economist doing business as Wilson Energy Economics, and Brendan Kirby, a private consultant. SACE/CCL subsequently filed amended direct testimony and exhibits for Witness Kirby on September 19, 2019. On September 11, 2019, ORS filed the direct testimony of Robert A. Lawyer, Senior Regulatory Manager in the Utility Rates and Services Division, and Brian Horii, Senior Partner at Energy and Environmental Economics, Inc. ("E3"). Exhibits were included with the direct testimony of Witness Horii.

On September 30, 2019, Nucor filed a letter in lieu of prehearing brief in which Mr. Smith also requested protection from appearing at the hearing.

On October 2, 2019, the Companies filed the rebuttal testimony of Witnesses Brown, Snider, Wheeler, Johnson, Wintermantel and John Samuel Holeman III, Vice-President of the System Planning and Operations Department for Duke. Exhibits were included with the rebuttal testimony of Wheeler, Johnson and Wintermantel.[13]

On October 11, 2019, Johnson Development filed the surrebuttal testimony of Witness Chilton and SCSBA filed the surrebuttal testimony of Witnesses Levitas, Davis,

[11] SCSBA inadvertently failed to file the Direct Testimony and Exhibits of Witness Levitas in Docket No. 2019-186-E and did so on September 17, 2019.
[12] Portions of Burgess's Direct Testimony contain confidential information and were filed under seal pursuant to Order No. 2019-680.
[13] The Companies did not request Mr. Wintermantel's rebuttal exhibit be entered into the record during the hearing.

Downey and Burgess. SACE/CCL filed the surrebuttal testimony of Witness Wilson and Kirby on October 11, 2019. ORS filed the surrebuttal testimony of Witness Horii on October 11, 2019. SCSBA filed amended surrebuttal testimony of Witness Burgess on October 17, 2019. SACE/CCL filed amended surrebuttal testimony for Witness Kirby on October 18, 2019.

On October 15, 2019, ORS filed the unredacted direct testimony and surrebuttal testimony of Witness Horii that was previously filed under seal, but after consultation with the Companies, determined that the previously redacted versions of Witness Horii's testimony did not contain confidential information.

On October 21, 2019, at the beginning of the hearing, counsel for the Companies notified the Commission that the Companies and SCSBA, Johnson Development and SACE/CCL (the "Settling Parties") had come to an agreement regarding the solar Integration Services Charges ("SISC").[14] Ecoplexus, while not a signatory, supported the settlement. The Settling Parties agreed to the use of the SISC proposed by the Companies which is \$1.10/MWh (DEC) and \$2.39/MWh (DEP), and agreed that the SISC should be fixed for the duration of the PPA. As part of the agreement, the Companies agreed to submit proposed guidelines by November 18, 2019, outlining the requirements for QFs to become "controlled solar generators" and thereby avoid the SISC. In accordance with the terms of the settlement, the Settling Parties agreed to waive cross-examination of Duke Witnesses Wintermantel and Holeman and SACE/CCL Witness Kirby. The Settling Parties further agreed to waive cross-examination on the portions of testimony from Duke

[14] The Partial Settlement Agreement was entered into the record as Hearing Exhibit 1.

Witnesses Snider and Wheeler, SCSBA Witness Burgess and ORS Witness Horii that related to the SISC.

The Commission conducted an evidentiary hearing on this matter on October 21, 2019, and October 22, 2019, in the hearing room of the Commission with the Honorable Comer H. Randall presiding.

On October 21, 2019, Duke Witnesses Brown and Snider appeared as the Companies' first panel of witnesses. Witnesses Brown and Snider gave summaries of their direct testimonies and answered questions from counsel and the Commission. Witness Brown testified regarding the requirements of PURPA, specifically as it relates to the mandatory purchase obligation, and the requirements of Act 62 as they relate to PURPA. Witness Snider provided testimony in support of the Companies' use of the peaker methodology for the calculation of avoided cost and the Companies' rate design. Next, Duke presented its second panel of witnesses, Witnesses Wheeler and Johnson, who provided summaries of their direct and rebuttal testimonies and answered questions from counsel and the Commission. Witness Wheeler provided testimony in support of the Companies' Standard Offer Tariffs, Standard Offer PPA and the standard offer terms and conditions applicable to QFs with a capacity of 2 MW or less. Duke Witness Wheeler also provided testimony in support of requiring a QF to deliver power within 30 months to ensure retail customers are not paying stale and inaccurate avoided cost rates due to extended delays in the construction of a QF. Witness Johnson's testimony was given in support of the Companies' Large QF PPA available for projects greater than 2 MW as well as the Companies' Notice of Commitment Form. The Companies then presented Witness

Wintermantel who provided a summary of his direct and rebuttal testimony and answered questions from the Commission. Duke Witness Wintermantel provided testimony to the Commission in support of the solar ancillary service study completed by Astrapé for the Companies, which supports the calculation of the SISC.

SCSBA and Johnson Development then presented a joint panel of SCSBA Witness Levitas and Johnson Development Witness Chilton. Witness Levitas testified regarding his concerns with the Companies' proposed Standard Offer PPA and terms and conditions, Large QF PPA and Notice of Commitment Form. Witness Chilton provided testimony regarding PPA duration and market rate financing. SCSBA then presented its second panel, which included SCSBA Witnesses Burgess, Davis and Downey. Witnesses Burgess and Davis provided summaries of their direct testimony. Witness Burgess testified regarding his concerns of the Companies' incentive structure, which he suggested provides an incentive to pursue low avoided cost rates, as well as his concerns regarding traditional utility-owned generation. Witness Davis provided testimony concerning Act 62's avoided cost requirements. SCSBA Witness Downey then provided a summary of his direct and surrebuttal testimony in which he addressed the economic development of solar companies as it relates to increased competition in electric generation.

The Commission reconvened the hearing on October 22, 2019, at which time SACE/CCL presented Witness Kirby. Witness Kirby provided a summary of his direct and surrebuttal testimony, which included his comments about the SISC as well as the solar ancillary service study. Next, SACE/CCL Witness Wilson provided a summary of his direct testimony in which he addressed aspects of the Companies' proposed avoided capacity rate design. ORS then presented its panel of witnesses, Horii and Lawyer. Witness Horii provided a summary of his direct and surrebuttal testimony in which he supported the Companies' avoided energy costs and avoided capacity costs, but offered proposed changes to the lifetime of a CT and provided recommendations for the seasonal allocation of capacity costs. Witness Lawyer testified regarding the Companies' compliance with sections of Act 62. Next, the Companies presented their rebuttal case and recalled Witnesses Brown and Snider. Witness Brown provided testimony regarding the recent Notice of Proposed Rulemaking on PURPA implementation issued by FERC. Witness Snider explained how SCSBA's emphasis on the need to promote competition between the utilities and QFs demonstrates a fundamental misunderstanding of Act 62 and PURPA. Next, the Companies presented rebuttal Witness Holeman who testified regarding the challenges and operational circumstances that the Companies' system operators experience with growing levels of solar QFs. SCSBA then recalled Witnesses Burgess and Davis to give summaries and testify regarding their surrebuttal testimony. Witness Burgess testified that the Companies' inclusion of coal in DEC's and DEP's Integrated Resource Plans ("IRPs") could have the effect of suppressing avoided cost values, and provided updated calculations for his proposed alternative seasonal allocation of capacity values. Witness Davis testified regarding the Companies' failure to appreciate the historical and future capacity contributions from solar. SACE/CCL then recalled Witness Wilson to provide his surrebuttal testimony in which he further explained his concerns regarding the studies used to support the Companies' proposed seasonal capacity payment allocation.

At the conclusion of the evidentiary hearing, at the request of Johnson Development counsel to include late-filed exhibits regarding alternative PPAs, it was agreed that Johnson Development and SCSBA would provide a proposal of dates for consideration by the Commission and hearing officer. Johnson Development and SCSBA jointly filed a proposed schedule for post-hearing submissions on October 23, 2019. Hearing Officer Randall Dong issued a Directive for parties to respond by October 28, 2019.[15] The Companies filed a response as directed, and on October 31, 2019, a Directive was issued by Hearing Officer Dong stating it is permissible to include proposals that are based on the evidence and testimony in the record of the case in the Parties' proposed orders, but that it would be inappropriate to attempt, at this time, to enter additional evidence or testimony into the record.[16] The parties filed proposed orders on November 8, 2019.

II. SUMMARY INTRODUCTION TO COMMISSION DECISION

This case is the first proceeding to address the Companies' avoided costs and PURPA implementation since Act 62 was enacted. The record in this case is robust—over 800 pages of testimony and over 700 pages of exhibits were submitted by Duke, ORS, and intervening parties. This is also the first case in which the Commission retained an independent third-party consultant to help inform the Commission's decision regarding Duke's avoided costs, as now provided for under Act 62. The statutorily-mandated purpose of the case is for the Commission to set avoided cost rates for QFs selling their output to Duke pursuant to PURPA and to approve commercially reasonable contract terms to

[15] Order No. 2019-126-H.
[16] Order No. 2019-128-H.

govern those sales of power, consistent with PURPA and Act 62. However, the testimony and evidence presented to the Commission for consideration on those matters has been much broader.

The Commission heard extensive arguments, some more relevant than others, over the potential for utility bias against QFs, inherent risks to customers in developing utility and QF generation sources, and the existence (or lack thereof) of competition between utility generation and QF power. As a basic premise, the Companies maintained that because costs associated with PURPA contracts are statutorily passed through to customers, the Companies are financially indifferent to QF purchases. Therefore, Duke's interest in this proceeding generally aligns with customers' interest in ensuring that customers pay no more than the avoided costs required by PURPA. Customer groups including SCEUC and Nucor have advocated for the Commission to set avoided cost rates as low as reasonably possible consistent with the statutory requirements of Act 62. (Tr. Vol. 2, p. 588-589; Exhibit No. 18.) In contrast, SCSBA has advocated that avoided cost rates should be set at the higher end of a "zone of reasonableness" to foster Act 62's goal of encouraging renewable energy. Additionally, Duke has consistently emphasized that the "indifference principle" under PURPA prohibits the Commission from setting avoided costs to incentivize or subsidize the development of QFs above the actual costs to be avoided by purchasing power from QFs.

Duke has also raised concerns about the significant financial obligation its customers are incurring as a result of the unprecedented amount of solar QFs selling their output to the Companies under PURPA at rates that exceed the utilities' most current projections of avoided cost. Duke's customers have experienced first-hand the risk associated with longer-term fixed avoided cost rates that decline as time progresses. In considering these challenging issues, the Commission has followed the General Assembly's direction in enacting Act 62 to find that 10-year fixed price contracts appropriately balance the risks to customers of longer-term fixed price rates with the interests of the QF industry in the near term.

In assessing risks for the using and consuming public in this proceeding, the Commission has carefully considered the reality that utility customers will inevitably overpay for QF purchases if avoided cost rates in the future turn out to be higher than the administratively-forecasted avoided cost rates established by the Commission today. This "over-payment" risk is a concern the Commission has attempted to manage in this Order by accurately setting avoided cost rates to be paid to QFs over the next 10 years.

SCSBA and Johnson Development have also characterized the utilities as attempting to oppose competition from solar generation, arguing that the influx of solar generation endangers the ability of the utility to build new generation. These parties have suggested that the development of utility generation is riskier than development of QF facilities due the potential for cost overruns. However, the Companies pointed out that Duke is fully committed to competitively procuring significant solar energy for its customers, and that the Commission and intervenors have opportunities in rate proceedings to ensure that only prudently incurred costs of utility owned generation are recoverable, and that cost savings are passed onto customers through lower cost of service.

Duke has highlighted the significant additional amounts of solar it plans to incorporate in the near-term and long-term. The Companies project up to 1,300 MW of solar capacity to be procured through the independently-administered Competitive Procurement of Renewable Energy ("CPRE") Program over the next few years and anticipate 8,300 MW of total installed solar capacity combined between DEC and DEP, to serve customers' energy needs over the next 15-year IRP planning period.

With regard to future generation construction, the Commission recognizes that with increased oversight of resource planning and additional tools for certifying new generation (which may or may not be owned by the utility) included in Act 62, this Commission has never had more tools to ensure that the generation resource mix serving South Carolinians is reasonable, appropriate, reliable, affordable and diversified.

The Commission is also mindful that setting avoided cost rates is not wholly discretionary to this Commission. In this Order we fully explain the legal framework that guides us to determine the utilities' avoided costs as defined by PURPA and have endeavored to set rates that reflect the utilities' full and accurate avoided costs. As argued by Duke, the setting of those rates cannot be used to incentivize solar and other renewable generation as such an outcome is beyond the Commission's authority under PURPA and thereby prohibited by Act 62. The Commission notes that while Act 62 is unquestionably designed to *encourage* renewable energy, the General Assembly intended such encouragement to result through a variety of provisions (such as net metering, the voluntary energy renewable programs, and others), and not specifically through the PURPA provisions of Act 62. The PURPA provisions of Act 62 reinforce the level playing field established for QFs by Congress and FERC, supporting nondiscriminatory treatment for all sources of generation. The Commission's task here is to fully and accurately determine the utilities' real and quantifiable avoided costs, consistent with long-standing PURPA principles, despite the policy positions advanced by parties to this case.

Through this Order, the Commission is also approving the terms of the SISC Settlement between Duke and the solar industry and environmental intervenors in this proceeding. The Commission believes the Settlement presents a reasonable accommodation among the parties regarding the contentious and complex issues surrounding variable resource integration charges. The Commission appreciates the settling parties' efforts to reach an agreement on this issue.

In addition to establishing avoided cost rates pursuant to PURPA, Act 62 also requires the Commission to approve contracts with commercially reasonable terms and conditions through which QFs may sell their output to the utilities. We are pleased at efforts undertaken by the Companies and the intervenors to incorporate the recommendations of each others' witnesses and work toward reaching agreement on as many provisions of the contracting documents as possible. As such, only a handful of contracting issues remain in dispute for the Commission to decide in this Order.

As to the term of contract for larger QF power purchases, the Commission has—very late in the proceeding—been asked through SCSBA and Johnson Development's Proposed Orders to consider extended contract terms longer than the 10-year term prescribed by Act 62. SCSBA and Johnson Development have not explained their failure to properly put forward such proposals into the evidentiary record in this proceeding.

Regardless of the rationale for this oversight, as a threshold matter, such late-filed proposals do not satisfy the procedural requirements of Act 62, the Commission's Rules of Practice and Procedure, or the South Carolina Administrative Procedures Act, and as a result, the Commission declines to consider this untimely presented information, as it is not evidence upon which the Commission may make a conclusion in this case. A contract length of 10 years, as timely set forth by the Companies and properly entered into the evidentiary record, is, indeed, consistent with the Act. If intervenors choose to make such alternative proposals in future avoided cost cases, the Commission urges them to be made in a timely manner that complies with Act 62 and affords Duke, the ORS and customers a reasonable opportunity to consider and comment on such proposals.

The issues put forward by the parties in this proceeding are representative of the dialogue surrounding the energy future of South Carolina as renewable energy continues to become a more significant component of the State's generation mix, and this will not be the last the Commission hears of such issues. However, the scope of the PURPA implementation issues to be addressed pursuant to Act 62 is explicit, and the Commission's determinations in this case reflect that scope set forth by the General Assembly. This Order represents a logical and evidence-based determination of all issues in this docket, informed by the opinion of the Commission's third-party independent consultant, and follows the intent and direction of the General Assembly in Act 62, which gave rise to this proceeding.

III. GUIDING LEGAL FRAMEWORK: PURPA AND ACT 62

A. Jurisdiction

This Commission has jurisdiction over the Companies' Joint Application, as the Companies are electrical utilities under the laws of South Carolina and their operations are subject to the jurisdiction of this Commission. The Companies are also subject to Act 62, which, in pertinent part, requires the Commission to conduct biennial proceedings to oversee South Carolina's electrical utilities' compliance with the federal PURPA law, including review and approval of the Companies' avoided cost methodologies and rates, Standard Offer, form PPAs for QFs not eligible for the Standard Offer, as well as standard notice of commitment to sell forms available to all small power producer QFs as part of the State's PURPA implementation framework. S.C. Code Ann. § 58-41-20(A). Accordingly, the Companies' Joint Application seeks Commission approval of DEC's and DEP's avoided cost methodologies and rates, Standard Offer tariffs, form contract power purchase agreements, commitment to sell forms, and other related terms and conditions as required by Act 62.

B. PURPA Framework and Mandatory Purchase Requirements

Pursuant to Sections 201 and 210 of PURPA, electric utilities, such as DEC and DEP, are required to interconnect with and to offer to purchase electric energy from qualifying cogeneration and small power production facilities or "QFs." *See* 16 U.S.C. § 824a-3(a). This is known as the "mandatory purchase obligation" under PURPA. *See generally Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, 168 FERC ¶ 61,184 at ¶76 (Sept. 19, 2019) ("PURPA NOPR") (noting that PURPA's mandatory purchase requirements are a benefit of QF certification). PURPA requires the rates that electrical utilities pay to purchase QF energy shall not exceed the purchasing electrical utilities' "avoided costs," which PURPA defines as the incremental cost to the electric utility of the electric energy, which, but for the purchase from such QFs, such utility would generate or purchase from another source. *See* 16 U.S.C. § 824a-3(b), (d.) PURPA also requires that the rates for purchases of QF power be set at levels and in a manner that is just and reasonable to the utility's customers, in the public interest, and nondiscriminatory towards QFs. *See* 16 U.S.C. § 824a-3(b)(l); (2).

In enacting PURPA, Congress directed FERC to prescribe regulations to encourage the development of cogeneration and small power production facilities under PURPA, and delegated to state commissions the responsibility of implementing FERC's regulations, including PURPA's mandatory purchase obligation. *See* 16 U.S.C. § 824a-3(f); *see also FERC v. Mississippi*, 456 U.S. 742,750-51, 102 S.Ct. 2126 (1982). In 1980, FERC issued its rulemaking order, Order No. 69, establishing regulations to implement PURPA. *See Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128, (1980) ("Order No. 69"). Amongst FERC's regulations to implement PURPA, FERC prescribed additional details regarding electric utilities' obligation to purchase energy and capacity made available by QFs, including expressly prescribing that electric utilities shall not be required to pay more than the avoided costs for purchases from QFs. *See* 18 C.F.R. § 292.303(a); 18 C.F.R. § 292.304(a)(2).[17]

FERC also recognized in Order No. 69 that smaller QFs could be challenged by the transactional costs of bilaterally negotiating individualized rates with electric utilities, and required states implementing PURPA to make standard rates and terms available to QFs that are 100 kilowatts ("kW") and smaller. 18 C.F.R. § 292.304(C). FERC's regulations therefore provide that states "may" put into effect standard rates for purchases for QFs larger than 100 kW, explaining "that the establishment of standard rates for purchases can significantly encourage cogeneration and small power production, provided that these standard rates *accurately reflect the costs* that the utility can avoid as a result of such purchases." *See Order No. 69,* at 12,223 (emphasis in the original). Thus, in setting the mandatory purchase obligation requirements under its regulations, FERC mandated that standardized avoided cost rates should be made available to small QF generators of 100 kW or less (which became known as the "standard offer"), while leaving it to the implementing states and state commissions to determine whether to set standardized avoided cost rates for QF generators sized greater than 100 kW. As discussed further below, Act 62 now extends the standard offer requirements in South Carolina to all small power producer QFs 2 MW or smaller. *See* S.C. Code Ann. § 58-41-10(15).

[17] The Commission recognizes that FERC recently issued the PURPA NOPR to reconsider certain aspects of the mandatory purchase requirements prescribed in 18 C.F.R. § 292.304. These proposed regulations are not final regulations and have not yet been adopted by FERC. Accordingly, they are not binding on the Commission in its efforts to implement PURPA in South Carolina at this time.

C. Act 62 Requirements

The General Assembly's recent enactment of Act 62, in part, enacted S.C. Code Ann. § 58-41-20, which prescribes a new biennial review and approval process for the Commission to administer PURPA implementation in South Carolina. While the Commission has always had the exclusive authority and responsibility to oversee the State's implementation of PURPA in compliance with the regulations established by FERC, Act 62 sets a specific procedural framework through which the Commission must consider these issues. Also, while the Commission's previous review of the Companies' PURPA implementation has been specific to each electrical utility's standard offer, Act 62 expressly requires the Commission to review and approve form PPAs for QFs not eligible for the Standard Offer as well as standard notice of commitment to sell forms available to all small power producer QFs as part of the State's PURPA implementation framework. *See* S.C. Code Ann. § 58-41-20(A),(C),(D).

Importantly, Act 62 does not modify the foundational requirements of PURPA and defines "avoided cost" consistently with FERC's implementing regulations. *See* S.C. Code Ann. § 58-41-20(A); *c.f.* 18 C.F.R. § 292.304(A). In fact, Act 62 mandates that South Carolina's PURPA implementation must be "consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders," and expressly requires the Commission's determination of the rates for purchase from QFs to be "just and reasonable to the ratepayers of the electrical utility, in the public interest . . . and nondiscriminatory to small power producers." *See generally* S.C. Code Ann. § 58-41-20(A). In addition, Act 62 further prescribes that the Commission's implementation of

PURPA in South Carolina "shall strive to reduce the risk placed on the using and consuming public." *Id.* The risk of PURPA implementation exists for electrical utility customers, in part, because customers are responsible for paying the cost of all power purchased from QFs through the annual fuel factor. *See* S.C. Code Ann. § 58-27-865.

Act 62 also prescribes that the Commission shall "treat small power producers on a fair and equal footing with electrical utility owned resources by ensuring that:

> (1) rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs;
> (2) power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA; and
> (3) each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment. Avoided cost methodologies approved by the commission may account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility."

S.C. Code Ann. § 58-41-20(B). For larger QFs not eligible for the Standard Offer, the avoided cost rates offered by an electrical utility to a small power producer not eligible for the standard offer must be calculated based on the avoided cost methodology most recently approved by the commission. S.C. Code Ann. § 58-41-20(C).

Act 62 further prescribes certain express requirements for purchased power agreements ("PPA") offered by electrical utilities to small power producers, as well as requirements to be included in notice of commitment forms, each of which is further addressed in this Order. S.C. Code Ann. § 58-41-20(D)-(E).

In sum, Act 62 directs the Commission to review each South Carolina electric utility's avoided cost rates and PURPA implementation every two years beginning six months from the Act's effective date, specifically including approving the utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement the mandatory purchase requirements of PURPA. This proceeding is the Commission's first biennial review of DEC's and DEP's avoided cost rates under the new requirements of Act 62.

D. Independent Third-Party Consultant Review of Electrical Utility's Calculation of Avoided Costs and PURPA Implementation under Act 62

Section 58-41-20(I) of the Act authorizes the Commission "to employ, through contract or otherwise, third party consultants and experts in carrying out its duties under [the Act], including, but not limited to, evaluating avoided cost rates, methodologies, terms, calculations, and conditions[.]" Pursuant to that authority, on September 3, 2019, the Commission engaged Power Advisory LLC ("Power Advisory") to serve as the independent third-party consultant. On November 1, 2019, Power Advisory submitted its *Independent Third Party Consultant Final Report Pursuant to South Carolina Act 62* ("Power Advisory Report") to the Commission, presenting its independently derived conclusions as to DEP's and DEC's calculation of avoided costs as well as other aspects of Act 62 implementation. The Power Advisory Report found Duke's avoided cost filing and subsequent responses to data requests and requests for production of documents in support of the Companies' avoided cost filing to be reasonably transparent, as required by S.C. Code. Ann. § 58-41-20(J). *Power Advisory Report*, p. 9. The Act provides that "[a]ny conclusions based on the evidence in the record and included in the report are intended to be used by the commission along with all other evidence submitted during the proceeding, to inform its ultimate decision setting the avoided costs for each electrical utility. *See* S.C. Code Ann. § 58-41-20(J). The Commission's Order addresses Power Advisory's substantive findings and conclusions and the Commission has appropriately considered Power Advisory's conclusions based on the evidence in the record to inform the Commission's ultimate decision in setting DEC's and DEP's avoided cost rates as well as other Commission determinations in these proceedings.

IV. FINDINGS OF FACT

Based upon the Joint Application, the testimony, and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission hereby makes the following findings of fact:

A. Risks of PURPA Implementation for the Using and Consuming Public

1. In implementing the PURPA rate setting requirements of Act 62, the Commission must strive to reduce the risk placed on the using and consuming public. Risks exist with both longer-term fixed price contracts paid to QFs under PURPA as well as with traditional utility generating resources. In this proceeding, the Commission is tasked with setting avoided cost rates that are nondiscriminatory to QFs, just and reasonable for consumers, and that minimize the risks to consumers of South Carolina's implementation of PURPA.

2. The Commission's comprehensive regulation of public utility generation through certification of planned new generating facilities and cost of service-based

ratemaking is fundamentally different from the Commission's task in these proceedings to approve forecasted avoided cost for energy and capacity to be paid to QFs under PURPA.

3. Risks associated with construction of public utility generation are not necessarily offset by QF solar generation because solar generation cannot fully replace non-solar generation as a capacity resource; therefore, there is no demonstrable corresponding reduction in risk to customers from a comparison of capacity resources, despite the arguments of SBA and JDA.

4. Act 62 requires electrical utilities to offer 10-year fixed price power purchase agreements for the purchase of energy and capacity from small power producer QFs at each electrical utility's avoided cost until the total capacity of executed interconnection agreements and power purchase agreements equals 20 percent of DEC's and DEP's previous five-year average South Carolina retail peak load. Neither DEC nor DEP have met the 20 percent threshold set forth in the Act. Therefore, the Commission is following the General Assembly's direction to approve 10-year contract terms as reasonably balancing the over-payment risks for consumers of longer term fixed price avoided cost contracts while fully and accurately calculating DEC's and DEP's avoided costs.

B. Duke's Avoided Cost Rates Do Not Reflect Anti-Competitive Bias Against Solar QFs

5. The evidence in this proceeding does not support SCSBA's arguments that Duke has developed avoided cost rates that are anti-competitive or biased against future development of solar QFs. Duke made only two adjustments to its 2019 integrated resource

planning inputs and assumptions in developing its avoided cost rates, both of which increase the avoided cost rates that will be paid to QFs.

6. DEC and DEP are also promoting meaningful competition in the future development of solar generation through the Competitive Procurement of Renewable Energy Program ("CPRE Program"). Duke is currently soliciting 680 MW of new solar capacity to serve customers' energy needs through the CPRE Program. This competitive solicitation benefits consumers by requiring new solar capacity to provide dispatch rights and bid in at rates below current avoided costs. Over the next 15-year IRP planning period, Duke is also projecting adding significantly more solar capacity, up to a total installed capacity of approximately 8,300 MW combined between DEC and DEP, to serve customers' energy needs. Therefore, solar is a significant part of DEC's and DEP's current and future generation portfolio.

7. Solar QFs do not displace the need for Duke to also plan for other types of dispatchable load-following generation, such as natural-gas fired generation.

C. Peaker Methodology

8. The peaker methodology as applied by DEC and DEP is a reasonable and appropriate methodology to fully and accurately quantify DEC's and DEP's forecasted capacity and energy cost to be avoided by purchases from QFs.

D. Avoided Energy Cost Quantification and Rate Design

9. Duke's modeling methodology and input assumptions used to calculate DEC's and DEP's avoided energy cost rates are reasonable.

10. DEC and DEP have accurately quantified their avoided energy costs for purposes of this proceeding.

11. DEC's and DEP's proposed avoided energy rate design ensures that avoided cost rates accurately compensate QFs for the value of the energy they provide to the Companies and customers, consistent with PURPA, FERC's implementing regulations, and Act 62.

E. Calculating Avoided Energy Rates for Large QFs

12. To accurately quantify DEC's and DEP's avoided costs for Large QFs not eligible for the Standard Offer, it is appropriate for DEC and DEP to recognize the QF's actual energy production profile, and to incorporate the most up-to-date inputs under the approved peaker methodology, in calculating a non-Standard Offer PPA QF's avoided energy rates.

F. Avoided Capacity Quantification and Rate Design

13. DEC and DEP have appropriately identified their first avoidable capacity need, as presented in the utilities' 2019 Integrated Resource Plans.

14. In applying the peaker methodology, Duke has used reasonable "peaker" cost assumptions published by the United States Energy Information Administration ("EIA") for the cost of the avoided combustion turbine unit used to quantify the projected capacity value avoided by QF purchases.

15. In applying the peaker methodology, Duke has made reasonable assumptions about the 35-year useful life of the avoided combustion turbine unit consistent with DEC's and DEP's 2019 IRPs.

16. The performance adjustment factor capacity payment multiplier proposed by Duke is reasonable and supports Act 62's objective of placing QF generators and utility generators on equal footing in terms of reasonable allowance for unplanned outages.

17. DEC's proposed seasonal allocation weightings of 90% for winter and 10% for summer, and DEP's proposed seasonal allocation weighting of 100% for winter, should be used in calculating DEC's and DEP's avoided capacity rates in this proceeding.

G. Solar Integration Services Charge

18. DEC and DEP are incurring increased intra-hour ancillary services cost to integrate variable and intermittent solar generators. It is appropriate to recover these costs from the solar generators that are causing the cost through an Integration Services Charge. The solar Integration Services Charge ("SISC") Settlement agreed to between Duke, SCSBA, JDA, and SACE/CCL is a reasonable and appropriate resolution of the issues related to the SISC in this proceeding.

19. As set forth in the SISC Settlement, the Astrapé Study's determination that an additional 26 MW of load following reserves are required to integrate 840 MW of solar in DEC at an average cost of $1.10/MWh and that an additional 166 MW of load following reserves are required to integrate 2,950 MW of solar in DEP at an average cost of $2.39/MWh is reasonable and should be approved.

20. It is appropriate for Duke to prospectively apply the Integration Services Charge to all new uncontrolled solar generators that commit to sell and deliver power into the DEC and DEP systems. Such updated Charge approved by the Commission will be

applied to commitments to sell and deliver power created after the date of the filing of such updated Charge.

21. To promote transparency, as provided for in the SISC Settlement, Duke should undertake an independent technical review of the underlying modeling, inputs and assumptions of the Integration Services Charge prior to the next biennial avoided cost proceeding.

22. As set forth in the SISC Settlement, it is not appropriate for Duke to impose the Integration Services Charge upon QFs or "controlled solar generators" that demonstrate that their facility is capable of operating, and contractually agree to operate, in a manner that materially reduces or eliminates the need for additional ancillary service requirements incurred by the utility.

H. Standard Offer

23. The Standard Offer Tariff, Standard Offer PPA and Standard Offer Terms and Conditions, as modified by Duke in response to comments from the ORS and SCSBA, are commercially reasonable and should be approved for small power producer QFs up to 2 MW.

24. The Companies' requirement in the Standard Offer Tariff that QFs must deliver power within 30 months from the date of the order approving the Standard Offer Tariff is reasonable to ensure avoided cost rates paid by customers remain accurate and are not stale at the time the QF begins delivering power.

25. The Standard Offer Tariff and Standard Offer Terms and Conditions approved by the Commission in these proceedings properly apply to all existing QF Sellers, similar to the applicability of any other retail tariff offered by the Companies.

I. Large QF PPA

26. The Large QF PPA, as modified by Duke in partial response to comments and recommendations by the SCSBA, is commercially reasonable and should be the approved form of PPA for small power producer QFs that do not qualify for the Standard Offer.

27. The Companies have properly conditioned execution of the Large QF PPA on the QF executing and returning a Facilities Study Agreement to ensure the accuracy of avoided cost rates in light of modifications adopted at SCSBA's request to provide a flexible commercial operations date for QFs.

28. Allowing a QF Seller to terminate the Large QF PPA without penalty as a result of interconnection costs that exceed $75,000/MW is arbitrary, unreasonable and inconsistent with establishing a legally enforceable and binding commitment to sell.

29. The Companies' three forms of performance assurance currently offered under the Large QF PPA are commercially reasonable and the Companies shall not be required to offer a surety bond.

J. Notice of Commitment Form

30. The Notice of Commitment Form proposed by Duke is reasonable and ensures that QFs make a substantial and binding commitment to sell their output to the Companies when establishing a non-contractual legally enforceable obligation.

31. The Notice of Commitment Form provides QFs a reasonable period of time from submittal of the form to execute a PPA, and does not require the QF to execute a PPA prior to receipt of a final interconnection agreement as a condition of preserving pricing and terms and conditions established by submittal of the Form.

32. Requiring QFs to have secured all required permits and land use approvals before establishing a non-contractual legally enforceable obligation is reasonable and consistent with demonstrating a substantial and binding commitment to sell power to the utilities.

33. Requiring QFs to deliver power to the utility within 365 days of executing a Notice of Commitment Form is reasonable to protect customers from paying stale and inaccurate avoided cost rates.

K. Consideration of Longer Term Fixed Price PPA Proposal

34. Commission approval of a fixed price power purchase agreement with a duration longer than 10 years is not supported by the evidence in the record and is not in the best interest of the ratepayers at this time.

V. EVIDENCE AND CONCLUSIONS

A. Risks of PURPA Implementation for the Using and Consuming Public

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 1-4

The evidence in support of these findings of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Act 62 requires the Commission's decisions in this proceeding to, amongst other requirements, "strive to reduce the risk placed on the using and consuming public." S.C. Code Ann. § 58-41-20(A). The issue of what risks the Commission should consider and how the Commission should take such risks into account in meeting the requirements of the Act were the focus of considerable testimony in this proceeding.

Summary of the Evidence

Duke Witness Brown's direct testimony explained that Duke has recently gained significant experience with the over-payment risks of uncontrolled PURPA QF development under longer-term fixed PURPA contracts in North Carolina. From 2012 to 2017, installed solar QF capacity grew rapidly in North Carolina from approximately 77 MW to over 1,600 MW. Mr. Brown explained these long-term fixed-price purchase obligations have continued to grow during a time of steadily declining natural gas prices, and, today, the Duke utilities have almost 4,000 MW of QF PURPA power either installed or under contract across North Carolina and South Carolina. (Tr. Vol. 1, p. 46.13.) Mr. Brown highlighted that this surging QF growth during a period of declining avoided costs has resulted in long-term avoided cost payment obligations significantly in excess of the value that the QF power is delivering to customers, relative to the Companies' declining costs to generate electricity or to purchase alternative power. (Tr. Vol. 1, p. 46.14.) Specifically, he highlighted that DEC's and DEP's customers' current estimated financial obligation to purchase QF power is approximately $4.66 billion over the next approximately 15 years, while these contracts would have a significantly lower value of only $2.40 billion, if valued at today's significantly lower avoided cost rates. He explained that this results in a currently forecasted over-payment of approximately $2.26 billion, as compared to the Companies' current avoided cost rates. (Tr. Vol. 1, p. 46.16.)

Mr. Brown also identified the national discussion around the increasing over-payment risk of longer-term fixed price PURPA contracts, pointing to comments submitted to FERC in 2018 by the National Association of Regulatory Utilities Commissioners ("NARUC"). NARUC's comments highlighted similar experiences in Idaho and Montana to suggest that administratively forecasted avoided cost rates have dramatically overstated the actual market price of electricity. (Tr. Vol. 1, p. 46.15.)

In further describing the over-payment risk associated with longer-term QF contracts, Mr. Brown explained that, once Duke enters into a fixed price PPA with a QF, FERC has held that neither the utility nor the Commission may modify the QF's contract if changes in the Companies' avoided costs occur in the future. This effectively means that the Companies' customers are locked into paying for the QF's power at the administratively determined avoided cost rates for the full term of the PPA, regardless of whether market conditions change or whether the value of the QF energy and capacity decreases. He emphasized that once the regulatory framework is set and avoided cost rates are approved in this proceeding, the Commission has little control over the amount of new QF power that will be developed in response to the price signals set in this proceeding, and ultimately the cost that customers will bear to pay for that new QF power. (Tr. Vol. 1, p.46.15, Tr. Vol. 2, p. 621.26.)

SCSBA Witness Davis argued that Duke's concerns about overpayment risk to customers from long-term fixed price PURPA contracts are overblown and unfair. He argued that Duke's calculation of the difference between the financial obligations over the life of existing QF PPAs is based upon projections of future avoided costs which have not yet been approved by the Commission and that avoided costs may increase in the future. Mr. Davis suggested that while Duke's avoided cost have recently declined, future changes in natural gas prices and other factors may result in the current overestimation of avoided costs balancing out leaving customers unharmed. (Tr. Vol. 1, p. 391.8-9.)

Witness Davis also argued that Act 62 is not explicit in describing the kinds of risks the Commission should consider, and that the SCSBA believes that the Commission should consider a broad range of cost risk considerations in this proceeding. (Tr. Vol. 1, p. 391.8.) He testified that that there are numerous risks related to the construction and operation of utility-owned generating facilities that are not present with QF PPAs entered into under PURPA. Witness Davis specifically pointed to construction cost risks, such as the recent abandonment of Duke's Lee nuclear unit and Dominion Energy South Carolina's V.C Summer nuclear unit, as well as operating costs risks, such as changes in fuel expenses or environmental regulations that can increase the cost of operating utility owned generation in the future. (Tr. Vol. 1, p. 391.13-14.) Mr. Davis explained that these types of risk are absent from PURPA contracts because QF PPAs are performance-based, meaning small power producer QFs are only paid for the power and capacity actually delivered. (*Id.*)

JDA Witness Chilton presented similar arguments regarding the potential risks of utility-owned generation for customers. (Tr. Vol. 1, p. 334.8.)

In rebuttal, Duke Witness Brown disagreed with SCSBA Witness Davis' suggestion that the overpayment risk of longer-term fixed price contracts would balance out leaving Duke's ratepayers, who are obligated to pay for QF power, unharmed. Witness Brown again pointed to North Carolina's recent experience where longer-term fixed avoided cost rates have already resulted in $185 million in over-payments for PURPA power delivered during 2016-2018 under long-term fixed price contracts that exceed DEC's and DEP's current cost of energy. (Tr. Vol. 2, p. 621.28.) Witness Brown also highlighted findings from the recent FERC PURPA NOPR that experience across the country has shown that over-payment and underpayments under longer-term PURPA contracts have not balanced out and customers have not been left indifferent. (Tr. Vol. 2, p. 621.29.)

Finally, Witness Brown compared the greater potential for over-payment risk under the 10-year fixed price contracts required under Act 62 with the terms of PURPA mandatory purchase contracts in other southeastern states, noting that Duke has recently signed nine PPAs totaling 472 MW in North Carolina at that state's maximum five-year contract terms for administratively set PURPA rates. Mr. Brown further testified that the proposed fixed 10-year fixed avoided cost rates required under Act 62 will be the longest fixed rates offered under PURPA in the Southeast for projects larger than one MW. (Tr. Vol. 2, p. 621.25.)

Witness Brown also responded to the SCSBA's arguments about the risks of utility-owned generation versus QF purchases, explaining that the comparative risks of these two types of resources have no bearing on the calculation of DEC's and DEP's avoided costs and that such a comparison of risk profiles is entirely inapplicable to this proceeding. (Tr. Vol. 2, p. 621.30-31.) He specifically highlighted that PURPA has exempted QFs from most all aspects of State utilities regulation, including oversight of their profits, returns, and business operations, while the Commission exerts significant regulatory oversight over the construction and cost recovery of new utility-owned generation. (Tr. Vol. 2, p. 621.34.) Witness Brown pointed to the extensive certification process required for new utility generation, including new requirements established by Act 62. He then explained that once utility generation is constructed and placed into commercial operation, the utility is then subject to cost of service-based ratemaking with oversight and regulation from this Commission. This oversight ensures that costs were prudently incurred, and that any benefits or cost savings are passed on to customers. The Commission then has ongoing regulatory oversight of Duke's recovery of plant investments providing utility service, and can review items such as depreciation rates, the cost of capital being recovered by the utility, O&M costs to be collected, as well as any additional investment necessary in the plant to provide utility service. (Tr. Vol. 2, p. 621.30-31.) Witness Brown concludes that this ongoing regulatory oversight and cost recovery framework for utility-owned generation is fundamentally different than the PURPA avoided cost framework, explaining that the risks and benefits to customers achieved through cost-of-service ratemaking are not directly comparable to the risks and benefits customers face under a PURPA avoided cost framework. (*Id*.)

Additionally, in weighing the risks presented for consideration by the parties, it must be examined whether those risks provide any offset to other risks. Simply stated, there is no material or discernible risk from building non solar generation that is offset by building solar generation because one cannot automatically replace the other at all hours of the day—this is an issue of capacity. Duke witness Snider testified that solar generation cannot offset capacity need, explaining "[I]t's not like 1,000 megawatts of solar would ever displace 1,000 megawatts, even if you're a hundred percent allocation." (Tr. Vol. 2, p. 681, lines 17-24). Witness Snider continued, "No matter what the allocations were, when you say a 12,000 megawatt need, which you pointed out earlier, the incremental solar we're adding, once adjusted for its reliability equivalence, is just—even if it was summer, would be one or two thousand out of twelve. So it is very small, even if it was summer. We're not summer. We're winter. And in winter, it's ostensibly none." (Tr. Vol. 2, p. 682-83.)

In considering the relative risk of utility-owned generation, ORS Witness Lawyer testified during the hearing that utilities are not "guaranteed" a return on new capital investment, and that the ORS reviews all utility investments to ensure they are properly includible in rate base and all expenses to ensure they are reasonable and prudently incurred before they are authorized to be recovered in rates. (Tr. Vol. 2, p. 583.) He also agreed that the Commission has ongoing oversight over utilities' investments and can adjust rates to reflect changes in circumstances, such as the flow back of significant tax cuts in 2019 in response to the federal Tax Cuts and Jobs Act. (Tr. Vol. 2, p. 583.) He was not able to conclude whether the Commission had similar authority over QFs. (Tr. Vol. 2, p. 584.)

Finally, in addressing how the Commission should balance the over-payment risks of future QF contracts in South Carolina with the obligations of Act 62, Witness Brown testified during the hearing that the long-term fixed price nature of QF contracts creates the overpayment risk. He explained this overpayment risk could be mitigated through very short term contracts at fixed avoided cost rates or long-term contracts with periodic repricing; however, the General Assembly in enacting Act 62 has largely decided the issue of contract term in the near term, by requiring long-term fixed price 10 year contracts until each utility reaches the 20 percent of South Carolina retail peak load requirement, after which the Commission will set a different fixed contract term. (Tr. Vol. 2, p. 642-643.) Witness Brown testified that the 20 percent threshold for DEC is approximately 830 MW with approximately 80-100 MW committed today, while the 20 percent threshold for DEP is approximately 240 MW, with approximately 100-120 MW committed today. He testified that DEP is likely to achieve the 20 percent threshold sooner than DEC, potentially in the next year to 18 months. (Tr. Vol. 2, p. 736-737.)

Commission Determination

The Commission has carefully reviewed the extensive testimony in the record as it relates to how Duke, on the one hand, and the solar industry intervenors, on the other, advocate that the Commission view the requirements of Act 62 to "strive to reduce the risk placed on the using and consuming public" in deciding the issues before the Commission in this proceeding.

The Commission initially finds that the General Assembly's directive for the Commission to strive to reduce the risks to consumers is tied to the Commission's responsibility under Act 62 to implement the avoided cost requirements of PURPA. S.C. Code Ann. § 58-41-20(A) directs the Commission to ensure that South Carolina's PURPA implementation framework remains "just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers." *See* S.C. Code Ann. § 58-41-20(A). The General Assembly's direction for the Commission to also strive to reduce the risk on the using and consuming public must be harmonized with these other PURPA implementation requirements as well as the other provisions of S.C. Code Ann. § 58-41-20. *Senate of the S.C. v. McMaster*, 425 S.C. 315, 322 (2018) ("A statute must be read as a whole and sections which are part of the same general statutory law must be construed together and each one given effect").

In implementing these requirements, the Commission finds merit in Duke's position that the Commission should carefully consider the overpayment risk of administratively-forecasting avoided cost rates under longer term PURPA contracts that are increasingly uncertain and subject to future changes in the utilities' avoided costs. The Commission also finds persuasive Duke Witness Brown's testimony describing Duke's recent experience with PURPA implementation in North Carolina, as well as the similar experiences in other States across the country, as identified by NARUC.

The Commission also finds relevant the linkage of overpayment risk to longer-term avoided cost rates in light of Duke's uncontroverted testimony that the 10-year fixed avoided cost rates required under Act 62 will be the longest fixed rates offered under PURPA in the Southeast for projects larger than one MW. The Commission also notes Witness Brown's testimony that, while still a proposed regulation and in no way binding on this Commission, FERC's recent PURPA implementation NOPR is proposing to amend the avoided cost rate framework to provide states flexibility to mitigate the risks of longer-term fixed price contracts through more routinely updating the avoided energy rates. (Tr.

Vol. 2, p. 621.8.) Thus, the Commission finds the potential overpayment risk of longer term fixed-rate contracts to be an appropriate consideration in this proceeding.

The Commission also recognizes the testimony of SCSBA Witness Davis that risks exist with the planning, construction and operation of new utility-owned generating resources. Duke has not directly disputed this testimony, but argues that risks of utility-owned generation and QF generation are not comparable and that the costs and risks of utility generation are not directly before the Commission in this proceeding to implement PURPA. Furthermore, Duke pointed out that the Commission has existing authority to appropriately address the risks of utility-owned generation outside of Act 62.

The Commission agrees that there are fundamental differences between regulation of utility investments and the fixing of avoided cost rates that make comparing the risk of utility investments under cost of service-based ratemaking with the forecasting of utility avoided cost of little probative value. For example, when a utility builds a new generating facility and places it in rate base, it does not receive forecasted avoided costs for energy and capacity like QFs under PURPA. Instead, the utility is provided only a reasonable opportunity to earn a return on its invested capital and to recover its actually-incurred expenses to meet its obligation to serve customers. The utility also recovers its capital invested over significantly longer depreciation lives for utility-owned assets, which lowers the near-term rate impact for utility projects because lower annual depreciation costs are passed directly to customers through a lower revenue requirement. As recognized by ORS Witness Lawyer, customers also receive the benefit of future reductions in the utility's cost of service, such as the recent reduction in the federal corporate income tax rate and flow back of excess deferred taxes stemming from the Federal Tax Cuts and Jobs Act of 2017. In contrast, as Duke Witness Brown explains, PURPA provides developers of QFs with a guaranteed revenue stream for the duration of the avoided cost rates approved by the Commission. (Tr. Vol. 1, p. 46.12 (citing *New York State Elec. & Gas Corp.*, 71 FERC ¶ 61,027 (1995)).) This effectively means that the utility customers are locked into paying for the QF's power at the administratively determined avoided cost rates for the full term of the PPA, regardless of whether market conditions change or whether the value of the QF energy and capacity decreases.

It is clear from the testimony of Witness Snider that solar generation does not materially displace traditional utility capacity resources, and since the two types of generation are not interchangeable, the Commission concludes that there is no meaningful risk from one offset by the other. SBA and JDA essentially assert that solar generation could replace utility generation, and that the Commission should encourage such replacement through longer term contracts and higher avoided cost rates since such third-party QF generation is presumably less risky. However, since utility capacity cannot be materially offset by solar generation, the comparison fails. Additionally, the Company recognizes the operational challenges presented by Mr. Holman for must-take solar, and notes that system and operation risks are notable to the Commission even if they are not asserted by the parties.

The Commission takes not of the practice operation risk to the system that can be presented by and influx of solar generation. Duke Witness Holeman explained, "I've worked in and around system operators for 34 years, my entire career, I know of no other generation technology that presents this type of intraday variability and intrahour intermittency to the two system operators." (Tr. Vol. 2, p. 761.) Witness Holeman explained the challenges managed by system operators. "[In] the morning ramp-down, what we've seen, with solar and without solar, is basically a doubling of our ramping demand on the down ramp. And on the up ramp, we've seen a four times increase in the amount of ramping we have to have to meet both our load change and the solar generation change in those two hours. This particular graph illustrates the ramping challenges that our system operators are dealing with…the must-take solar generation that is currently, in this case, in the DEP balancing authority—Duke Energy Progress balancing authority." (Tr. Vol. 2, p. 760.) Given that solar generation is non-dispatchable, Mr. Holeman's explanation was key in understanding the everyday challenges of QF generation. This Commission is mindful of system reliability and the system operations that must be flexible enough to address current challenges. While not necessarily articulated in this case as a risk to the public, the Commission notes the operational risk nonetheless identified by Mr. Holeman in managing QF generation.

The Commission also notes that construction of new utility-owned generation must also be supported by the utility's resource planning and certification process, which is scrutinized by the ORS and other interested parties to ensure that utility investments in new generation are needed and can cost-effectively serve customers' future energy and capacity needs. Only after obtaining a certificate to construct new generation may a utility have the right to petition the Commission in the future to recover the costs of utility investments made to serve customers. The Commission finds that SCSBA makes a fair point that constructing new utility-owned generation creates potential risks for consumers, but it is a regulated risk overseen by this Commission under the public utilities laws and regulatory framework established by the General Assembly. In contrast, the Commission recognizes Duke Witness Brown's uncontroverted testimony that the Commission does not have a similar right to oversee QF investments and any savings from longer PPAs and lower financing costs are retained as profit by the QF developer and its investors and are not flowed through to customers. There are no limits on the amount of QF capacity that can be developed prior to the Commission's next review of Duke's avoided cost rates, such that the opportunity for QF development—and the associated cost risk for customers—is limited only by the accuracy of the forecasted avoided rates set in this proceeding. Based upon the foregoing, the Commission finds that SCSBA's focus on the risks to customers of utility-owned generation are offset by solar generation, and as such are not directly at issue in this proceeding and will properly be assessed in other dockets, including resource planning, certificate and general rate case proceedings before this Commission.

In sum, the Commission finds that the Commission's authority and responsibility to regulate the rates and service of public utilities in South Carolina is fundamentally different than the Commission's limited oversight of QFs through its implementation of PURPA. Accordingly, the Commission finds that comparing the risks of utility-owned generation and QF generation is not reasonable or persuasive. The Commission also finds that, in the near term, the General Assembly has made the express determination through Act 62 of the appropriate balancing of risks between QFs and customers by establishing that the avoided cost contracts to be offered to small power producer QFs shall be fixed for "a duration of ten years." *See* S.C. Code Ann. § 58-41-20(F)(1). Based upon the testimony offered by Duke Witness Brown, neither DEC nor DEP are have met the 20 percent threshold set forth in Act 62. Therefore, the Commission is following the General Assembly's mandate to approve fixed 10-year contract terms as reasonably balancing the over-payment risks for consumers of longer term fixed price avoided cost contracts and the General Assembly's goal of promoting renewable energy while fully and accurately calculating DEC's and DEP's avoided costs. In these current proceedings, this result appropriately meets the requirement for the Commission to strive to reduce the risks on the using and consuming public as part of its implementation of PURPA.

B. Duke's Avoided Cost Rates Do Not Reflect Anti-Competitive Bias Against Solar QFs

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 5-7

The evidence in support of these findings of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Act 62 requires the Commission to treat small power producers on a fair and equal footing with electrical utility-owned resources by, amongst other requirements, ensuring that "rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs." S.C. Code Ann. § 58-41-20(B)(1). Therefore, the Commission has a responsibility under the Act to ensure that Duke's avoided cost rates fully and accurately calculate the avoided capacity and energy costs to be avoided by purchases from QFs and that the utilities have not unjustly and unreasonably biased the development of these rates against small power producer QFs.

Summary of the Evidence

The SCSBA has argued extensively in these proceedings that Duke's Joint Application and proposed avoided cost rates are biased against solar QFs and are impeding the competition envisioned by Act 62 between QFs and the monopoly utilities. SCSBA Witness Downey asserted that South Carolina's cost of service regulatory regime is dominated by territorial monopolies and has been slow to evolve towards a more competitive model, as contemplated by Act 62. He further contended that proper implementation of Act 62 and PURPA in South Carolina would provide businesses like Southern Current the opportunity to compete with the utilities and that customers receive the benefits of that competition. (Tr. Vol. 1, p. 401.11.)

SCSBA Witness Davis similarly argued that small power producers compete directly with utilities for market share, and that Duke, as a monopoly utility, is biased against competition from solar QFs as the utility's business model is based upon earning returns for shareholders by investing in new generation, pollution control technologies, and grid-related improvements. He testifies that by keeping avoided cost rates artificially low, utilities can effectively shield themselves from competition to the benefit of shareholders and at the expense of ratepayers. (Tr. Vol. 1, p. 391.17.)

SCSBA retained Witness Burgess to evaluate Duke's quantification of DEC's and DEP's avoided capacity and energy costs. Mr. Burgess framed his recommended adjustments to Duke's calculation of avoided costs by suggesting that Duke has an incentive to propose artificially low avoided cost rates and to impose other barriers to competitive generators, such as the integration services charge in order to increase utility investments in new generation and natural gas infrastructure, while reducing competition from solar QFs. (Tr. Vol. 1, p. 382.10.) Witness Burgess argued that Duke has made many small but meaningful methodological choices in quantifying DEC's and DEP's avoided costs that, in the aggregate, result in avoided cost rates that are significantly biased against solar QFs. (Tr. Vol. 1, p. 382.11.) He also recommended that that the Commission should adopt avoided cost rates at the higher end of a "zone of reasonableness" as higher rates can encourage QF development and deployment and yield other benefits beyond utility avoided costs. (Tr. Vol. 1, p. 382.13.)

In rebuttal, Duke Witnesses Brown first testified that the SCSBA's arguments about promoting competition are a mischaracterization of the avoided cost framework and the purpose of the PURPA provisions of Act 62. Witness Brown explained that PURPA guarantees that the utility will purchase QF's output at Commission-approved rates and at no point does a QF need to "compete" with any other generation. (Tr. Vol. 2, p. 621.14.) He further contended that Witness Downey was also incorrect in his statement that customers will benefit from increased competition from solar QFs. Mr. Brown explained that this statement reflects a fundamental misunderstanding of the PURPA indifference principle and avoided cost framework, which are not designed to "benefit" customers but instead to leave them financially unaffected or "indifferent" to the purchase of the QF power. (Tr. Vol. 2, p. 621.15.) Witness Brown also pointed out that solar QFs do not have to compete on price or commercial terms as those rates and terms are administratively set by the Commission based upon the utility's projection of future avoided costs. (Tr. Vol. 2, p. 621.15-16.)

In response to the SCSBA's arguments that Duke is opposed to future competition from new solar QFs, Witness Brown pointed to the CPRE Program that Duke is undertaking pursuant to a 2017 North Carolina law supported by Duke. The CPRE Program is an independently administered competitive solicitation process designed to procure the most cost-effective utility-scale renewable energy resources across the DEC and DEP systems (whether located in North Carolina or South Carolina) at prices below the Companies' avoided costs. (Tr. Vol. 2, p. 621.17.) Witness Brown explained that Duke recently completed the "Tranche 1" CPRE solicitation, and procured approximately 550 MW of new solar capacity for 20-year fixed price contract terms at a projected savings relative to avoided cost of approximately $261 million over the 20-year term of PPA. Witness Brown also highlighted that both Southern Current and JDA successfully participated in CPRE Tranche 1, with affiliates of each of these developers winning proposals. He further testified that Duke's now-open "Tranche 2" CPRE solicitation will solicit a total of 680 MW of additional new renewable energy resources to be constructed between now and 2023. In total, Mr. Brown explained that Duke is planning to solicit up to 1,300 MW of new renewable energy capacity under the CPRE Program at rates below avoided costs over the next few years. (Tr. Vol. 2, p. 621.17-18.) Based upon this significant ongoing system-wide competitive solicitation of new solar capacity, Witness Brown contended that Duke is not attempting to shield itself from competition with solar

QFs as CPRE allows the SCSBA's members to compete directly with Duke and each other to deliver the least cost solar power to customers. (Tr. Vol. 2, p. 621. 19-20, 21.)

Duke Witness Snider also testified that SCSBA's argument that Duke is somehow incentivized to keep avoided cost rates as low as possible, or that Duke's calculation of avoided cost in this proceeding is somehow designed to render QFs economically infeasible or to reduce competition, is false and does not reflect the realities of the capacity and energy value provided by solar QFs. (Tr. Vol. 2, p. 630.6.) Witness Snider explained that deployment of QF solar does little to offset the need for future generation because it does not provide a net dependable resource capable of meeting future capacity requirements, which occur in predominately non-daylight hours. Adding non-dispatchable QF solar has little impact on DEC's and DEP's need for future generation but rather serves as a non-firm intermittent resource that reduces fuel purchases. (Tr. Vol. 2, p. 630.6, 7.) Witness Snider also explained that Duke is financially indifferent to purchasing QF power because its cost is a fuel pass-through expense paid directly by Duke's customers in the same way natural gas or coal fuel costs are a pass through. (Tr. Vol. 2, p. 630.6.) Witness Snider provided similar testimony during the evidentiary hearing. (Tr. Vol. 2, p. 680-682.)

Duke Witness Snider also responded to SCSBA Witness Burgess's argument that Duke's avoided cost rates are biased against solar QFs, explaining that these rhetorical arguments have no basis in reality. Witness Snider explained that Duke consistently uses the same system production cost models, data inputs, forward looking projections and planning assumptions to calculate avoided costs paid to QFs that Duke uses to identify the utilities' future energy costs and timing of planned generating resources shown in its integrated resource planning processes. (Tr. Vol. 2, p. 630.9-10.) With the exception of two discrete changes—both of which actually served to increase the avoided costs paid to QFs—Witness Snider explained that Duke's calculation of avoided cost rates paid to QFs are fully consistent with DEC's and DEP's 2019 IRPs, as recently filed with the Commission. The first adjustment was Duke's reliance on public Energy Information Association ("EIA") Combustion Turbine ("CT") cost data in developing capacity rates rather than lower cost proprietary engineering estimates of CT costs as used in the 2019 IRP. The EIA CT cost data yielded higher avoided capacity costs relative to Duke's internal CT costs assumptions. The second adjustment is to eliminate the incremental solar included in the Companies' IRPs over the 10-year avoided cost rate period in excess of installed and obligated solar. Mr. Snider explains that because each increment of solar generation reduces the value of the next increment, the Companies' avoided cost rates would have been lower if the Companies had fully accounted for the level of future solar capacity projected in their IRPs to be installed over the next 10 years. (Tr. Vol. 2, p. 630.10-11.) Witness Snider provided similar testimony during the evidentiary hearing. (Tr. Vol. 1, p. 125-126.)

Witness Snider also pointed out that it is the solar QF development industry that has a direct and substantial interest in avoided cost rates being set as high as possible to enable the highest profits for QF developers and their investors, which are paid for by the utility's customers. Based upon this fact, he recommends the Commission carefully consider the "methodological choices" that Mr. Burgess proposes on behalf of the solar industry to artificially raise Duke's avoided cost rates. (Tr. Vol. 2, p. 630.14-15.)

During the hearing, ORS Witness Horii testified that the limited capacity value provided by solar QFs would not be able to meet the capacity need that would arise as a result of coal unit retirements. (Tr. Vol. 2, p. 549-550.) Witness Horii also found Duke's avoided energy cost calculations to be reasonable and similarly found Duke's avoided capacity cost calculations to be reasonable except for two small changes that he recommended on behalf of ORS. (Tr. Vol. 2, p. 523-524.) Therefore, Mr. Horii did not find that Duke was biased in setting avoided costs.

During the hearing, Mr. Burgess also conceded that his advocacy for the Commission recognize a zone of reasonableness in order to adopt higher avoided cost rates would be unprecedented. (Tr. Vol. 1, p. 416.)

During the hearing, Witness Snider testified that Duke is not trying to block solar so that Duke's affiliates can build the Atlantic Coast Pipeline or so that Duke can build other generating resources. He emphasized that Duke has over 4,000 MW of additional solar in the 2019 IRPs and the utilities need a diverse portfolio of solar and other resources to serve customers. Therefore, both incremental solar and other resources such as natural gas generation are needed to reliably serve future load growth and accomplish coal unit retirements identified in the resource plans. (Tr. Vol. 2, p. p. 728-729.)

<u>Commission Determination</u>

The Commission has fully considered the evidence presented by the SCSBA and other parties on this issue and does not find that Duke's avoided cost rates reflect anti-competitive bias against solar QFs. To the contrary, the record supports that Duke has applied a fair and transparent methodology (discussed further below) to quantify avoided costs and, as testified to by Duke Witness Snider, has reasonably applied the same system production cost models, data inputs, forward looking projections and planning assumptions to calculate avoided costs paid to QFs that are used to identify the utilities' future energy costs and timing of planned generating resources in Duke's 2019 IRPs. Mr. Snider's uncontroverted testimony also shows that the two adjustments to Duke's 2019 IRP inputs and assumptions used in calculating avoided cost rates in this proceeding actually have the effect of increasing the avoided costs paid to QFs. The Commission also notes that ORS Witness Horii did not similarly allege that Duke's avoided cost rates were biased and has proposed only two adjustments, which the Commission addresses later in this Order. Thus, the Commission does not find any basis to conclude that Duke's avoided cost rates or other aspects of Duke's Joint Application in this proceeding are anti-competitive towards QFs or otherwise have the purpose or effect of impeding Act 62's directive that small power producers be treated on a fair and equal footing with electrical utility-owned resources. *See* S.C. Code Ann. § 58-41-20(B).

With regard to SCSBA's arguments that Duke has designed its avoided cost rates to impede competition between QFs and utilities, the Commission finds that these arguments cannot rationally be reconciled with the fact that Duke is continuing to provide QFs significant opportunities to develop new solar resources through the system-wide CPRE Program. This competitive solicitation enables solar QF developers to compete directly with Duke and each other to deliver new solar projects to customers at a price below the utilities' avoided cost. The Commission also finds persuasive that both Southern Current and Johnson Development actively participated in the CPRE Tranche 1 and are eligible for the now open Tranche 2. Finally, the Commission recognizes Duke Witness Snider's testimony that Duke's 2019 IRPs recognize the need for over 4,000 MW of additional solar. The Commission also finds Mr. Snider's testimony persuasive that Duke requires a diverse portfolio of generating resources, including both solar and natural gas resources, to serve customers' future energy needs and to accomplish the planned unit retirements identified in the Companies' IRPs. By fully and accurately quantifying Duke's avoided costs and otherwise implementing the PURPA requirements of Act 62, the Commission is providing solar QFs and all other eligible QF resources the non-discriminatory opportunity to provide this future energy and capacity to serve DEC's and DEP's customers.

The Commission also agrees with Duke Witness Brown that avoided cost rates are not market based and purchases from QFs at administratively-fixed avoided cost rates do not necessarily benefit customers. The objective of fixing avoided cost rates is to determine the price that leaves customers indifferent between purchasing power from traditional utility resources or from QF resources. (Tr. Vol. 2, p. 621.13 (citing *S. Cal. Edison Co.*, 71 FERC ¶ 61269, 62079–80 (1995)).) Under Act 62, as well as under PURPA generally, the Commission is obligated to treat both QFs and customers fairly by fully and accurately calculating the avoided capacity and energy costs to be avoided by purchases from QFs. *See* S.C. Code Ann. § 58-41-20(B)(1); 18 C.F.R. § 292.304(a). As further addressed in this Order, the Commission finds that Duke has applied a reasonable methodology and applied acceptable data and inputs to fully and accurate quantify DEC's and DEP's avoided costs to be provided to QFs.

C. Peaker Methodology

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 8

The evidence in support of this finding of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Act 62 directs the Commission to review and approve the methodology that the Companies use to establish avoided energy and capacity cost rates offered to QFs—including both smaller QFs eligible for the Standard Offer Tariff as well as QFs not eligible for the Standard Offer Tariff ("Large QFs")—to ensure that the electrical utility fully and accurately quantify the Companies' avoided capacity and energy costs and fairly account for costs avoided or incurred by the Companies, "including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers[.]" *See* S.C. Code Ann. §§ 58-41-20(A), 48-41-20(B)(1), (3).

Summary of the Evidence

Duke Witness Snider supports the Companies' continued use of the "peaker methodology" to quantify DEC's and DEP's avoided capacity and energy costs in these proceedings. Mr. Snider testifies that the Companies have historically applied the peaker methodology in both South Carolina and North Carolina to quantify each utility's avoided capacity and energy cost, and have consistently employed this methodology in these proceedings to meet the requirements of Act 62. Witness Snider's testimony explains how Duke applies the peaker methodology to quantify a utility's marginal capacity and energy costs based upon the avoided capacity cost of a simple cycle combustion turbine ("CT") or "peaker" unit plus the utility's forecasted avoided system marginal energy cost. (Tr. Vol. 1, p. 58.13.) Witness Snider states that the peaker methodology provides, consistent with PURPA, an appropriate and reasonable estimate of the utility's forecasted avoided or incremental costs of alternative energy that the utility would have otherwise incurred but for the purchase from a QF facility. (*Id.*)

Witness Snider explained that the peaker methodology is widely used throughout the electric industry and accepted as a fair, reasonable, and accurate means by which to calculate avoided costs. (Tr. Vol. 1 p. 58.12.) He also pointed out that the peaker methodology was recently recognized as an acceptable method for determining a utility's avoided cost in the widely relied-upon *PURPA Title II Compliance Manual* published by the NARUC, the Edison Electric Institute, and other industry organizations in 2014. (*Id.*)

Witness Snider testified that the Companies' application of the peaker methodology appropriately captures all avoidable marginal capacity and energy costs that consumers would otherwise pay "but for" the purchase from the QF and, as such, appropriately leaves the consumer indifferent to purchasing QF generation relative to the utility generating or purchasing alternative energy from another source. (Tr. Vol. 1 p. 58.22.) Witness Snider explained that the Companies rely upon several key elements in the application of the peaker methodology to accurately align the avoided capacity cost rates that customers ultimately pay with the actual value of the capacity delivered by the QF to the utility. These elements include: (a) calculating the annual avoided capacity value of a CT; (b) determining the year in which each utility has its first avoidable capacity need; (c) determining how annual capacity payments are made to the QF supplier; and

(d) applying an appropriate Performance Adjustment Factor in calculating the avoided capacity rate to allow the QF to receive full capacity value if its forced outage rate is equivalent to that of the Companies' overall generation fleets. (*Id.*) Witness Snider specifically pointed to the Performance Adjustment Factor capacity multiplier as an adjustment to the peaker methodology that is designed to place QF resources on fair and equal footing with utility-owned resources. (Tr. Vol 1, p. 58.21, 221.)

On behalf of ORS, witness Horii agreed that the Companies' use of the peaker methodology is consistent with PURPA and widely used throughout the country to calculate avoided energy and capacity costs. (Tr. Vol. 2 at 525.10 – 525.11.) In his direct testimony, ORS Witness Horii suggested that the Companies' approach to forecasting avoided energy costs was actually based upon the Differential Revenue Requirement ("DRR") methodology. (Tr. Vol. 2 at 525.7.) However, as Witness Snider explained at the hearing the DRR methodology is simply a "variant of the peaker" methodology, (Tr. Vol 1, p. at 122), and in any event, Witness Horii agreed that the Companies' avoided energy "calculation methodology is consistent with PURPA and the Commission's prior approval." (Tr. Vol. 2 at 525.10.) On behalf of SCSBA, Witness Burgess likewise does not voice an objection to the Companies' use of the peaker methodology, acknowledging that "the general framework (i.e. the Peaker Methodology) is sound[,]" (Tr. Vol. 1 at 382.44), while alleging that certain of the input assumptions utilized by the Companies are "biased against solar QFs" as discussed separately in this Order.

Power Advisory similarly finds Duke's application of the peaker methodology to be a "reasonable methodological basis for establishing the companies avoided costs." *Power Advisory Report*, p. 19.

Commission Determination

Taking into consideration the evidence presented, the general agreement among the parties that the peaker methodology is a proper methodology by which to calculate the Companies' avoided energy and capacity costs, as well as this Commission's past acceptance of Duke's use of this methodology in prior avoided cost proceedings, the Commission hereby finds that the peaker methodology is a reasonable and appropriate methodology to fully and accurately quantify DEC's and DEP's forecasted capacity and energy cost to be avoided by purchases from QFs and is consistent with the requirements of Act 62 and PURPA.

D. Avoided Energy Cost Quantification and Rate Design

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 9-10

The evidence in support of these findings of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

As part of the Commission's responsibility under Act 62 to approve Duke's avoided cost methodology, the Commission must also ensure that "rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs" including the utility's energy costs to be avoided by purchases from QFs. S.C. Code Ann. § 58-41-20(B)(1),(3) SCSBA has challenged aspects of Duke's quantification of its avoided energy rates and avoided energy rate design. In this section of the Order, the Commission first addresses Duke's quantification of avoided energy and then will address DEC's and DEP's avoided energy rate design.

Summary of the Evidence

Duke Witness Snider testified that the Companies calculate avoided energy costs under the peaker methodology by using a production cost simulation model called PROSYM. The PROSYM model analyzes the change in system production costs with and without a 100 MW block of no-cost generation (representing QF power) on an hourly basis over a 10-year period. The decrease in hourly production costs from the base case to the change case that includes the 100 MW of no-cost generation provides the marginal energy costs that can be avoided by the Companies over the 10-year avoided cost rate period. These avoided hourly energy costs are then used to calculate avoided energy rates consistent with the goal of leaving customers indifferent between QF power purchases and generation provided by the utility. (Tr. Vol. 1, p. 58.21-26.)

Duke Witness Snider testified that a number of inputs or factors in the PROSYM model drive avoided energy cost calculations over time, including load and energy forecasts, resource mix, unit characteristics, variable operation and maintenance ("VOM") costs, environmental emissions costs, reagent costs and fuel costs. He stated that although updating items such as VOM costs, environmental reagent costs, and the relative efficiency of the marginal unit with the most current information all factor into the utility's marginal cost of generation, recent changes in the commodity market price for natural gas represents the most significant change impacting the Companies' avoided costs. He explained that this was because natural gas commodity prices represent the primary driver of the avoidable energy cost since a natural gas-fueled combined-cycle unit or combustion turbine unit is often the marginal resource, and elaborated upon recent natural gas market changes in support of his claim. (Tr. Vol. 1, p. 58.22-23.)

In response to Duke's direct testimony, SCSBA Witness Burgess testified that production cost models generally solve for the optimal unit commitment and dispatch to meet system load at least cost. (Tr. Vol. 1, p. 384.21.) However, SCSBA Witness Burgess raised four main concerns with the Companies' avoided energy cost calculations and inputs to advocate for alternative, higher avoided energy rates. He first argued that the Companies' hourly modeling results incorrectly illustrate a significant fraction of hours that have negative avoided costs, which he further argued were an "artefact" of Duke's modeling "rather than what is likely to occur in real-world operations." Specifically, he suggested that constraints built in (Duke's) model such as transmission limits, generator minimum loading levels, generator ramp rates, and so on may bear no relation to real-world conditions or the actual operation of Duke's system. Therefore, Mr. Burgess contended that Duke's avoided energy rates may be above Duke's marginal value of energy. (Tr. Vol. 1, p. 384.21-27.) He then took issue with the Companies' fuel and commodity costs, arguing that coal is often on the margin in DEC and DEP-East while a future combined cycle gas unit is only primarily on the margin in DEP-West. In doing so, he recommended that separate regional avoided cost rates be calculated for DEP-East. Witness Burgess last argued that an avoided fuel hedge value, as well as an environmental cost adder representing coal ash costs, should be included in the Companies' avoided energy rates to further increase the avoided cost rates paid to QF developers. (Tr. Vol. 1, p. 384.28-42.)

ORS Witness Horii testified that the method used by the Companies to calculate avoided energy costs is consistent with PURPA and the methodology previously approved by this Commission. He further testified that he had reviewed the fuel price forecasts and other variables the Companies incorporated in calculating the avoided energy costs for this proceeding. Based upon his review, Mr. Horii testified that the forecast methodologies and values utilized by DEC and DEP were consistent with market knowledge of fuel prices and generator cost forecasts available at the time of the Companies' forecasts. He further testified that the most meaningful driver of the change in the Companies' avoided energy costs from previous years is the fuel price forecast change, and that it was reasonable to expect the change in avoided energy cost calculations to track closely with the change in fuel price forecasts. In conclusion, he testified that based upon his review, the avoided energy costs reflected in the Companies' Standard Offer tariffs were a reasonable result of the Companies' calculations, and that the Companies' calculations and methodology are consistent with PURPA and this Commission's prior approval. (Tr. Vol. 2, p. 525.7-10.)

In his rebuttal testimony, Duke Witness Snider provided support for the specific inputs included in the Companies' avoided energy cost calculation to rebut SCSBA Witness Burgess's claims. First, he explained that SCSBA Witness Burgess's concerns regarding the modeling of negative hours should be dismissed, because although Mr. Burgess's analysis accurately picks up on the negative value produced in one hour, he fails to recognize the offsetting benefit that occurred in the prior hour when making his claim.

As Witness Snider testified, the shifting of generator startup times when additional generation is added to the system occurs frequently in the production cost model as well as in the "real-world" during Duke's actual system operations. Moreover, changes in the hours that the Jocassee and Bad Creek Pumped Hydro assets pump and discharge water can also result in negative hours between the Companies' base and change case in the production cost model. Duke Witness Snider concluded by stating that discounting these negatives hours as "an artefact of Duke's modeling" when calculating the avoided energy rate would incorrectly inflate the avoided energy cost value that QFs provide to the Companies' customers. (Tr. Vol. 2, p. 630.23-26.)

Second, Witness Snider dismissed SCSBA Witness Burgess's concerns regarding the Companies' avoided fuel and commodity costs, and specifically, Mr. Burgess' argument that coal is often on the margin in DEC and DEP-East while a future combined cycle gas unit is only primarily on the margin in DEP-West. He explained that there were two issues underlying Witness Burgess's arguments: (1) Mr. Burgess misunderstood the use of the terms "marginal unit" and "marginal resource" in the context of how avoided energy costs are calculated, and (2) Mr. Burgess misunderstood that the DEP-East and DEP-West Balancing Authority Areas ("BAA") are interconnected. (Tr. Vol. 2, p. 630.26-29.) Witness Snider elaborated that "marginal resource" refers to the marginal avoidable generating units that reduced output when the 100 MW no-cost generation resource was added to the system in the change case. This definition of "marginal resource" is not synonymous with the system lambda or what is referred to as the "marginal cost" in production cost models. Instead, system lambda represents the cost of the marginal generating unit that can increase its output to supply the next 1 MW, which Mr. Burgess failed to appreciate in making his argument. (Tr. Vol. 2, p. 630.26-29.)

In response to Witness Burgess's recommendation to fix separate avoided energy rates for DEP-East, Mr. Snider explained that DEP is responsible for operating DEP-East and DEP-West as a single Balancing Authority that comprises both the DEP-East and DEP-West BAAs. DEP commits and operates the utility's generating fleet on an integrated basis to serve load across the entire DEP Balancing Authority, meaning separate avoided energy rates for DEP-East and DEP-West would always be the same, and represented as a single avoided energy rate. (Tr. Vol. 2, p. 630-26-29.) Duke Witness Holeman similarly provided testimony supporting the fact that DEP operates DEP-East and DEP-West as a single Balancing Authority and commits and operates the utility's generating fleet on an integrated basis to serve load across the DEP BA. He testified that DEP reserves a 400 MW firm transmission path between the DEP-East and DEP-West BAAs and commits and operates the utility's generating fleet on an integrated basis to serve load across the DEP Balancing Authority. (Tr. Vol. 2, p. 758.45-46, 763.)

Third, Duke Witness Snider refuted SCSBA Witness Burgess's argument that the Companies should include a separate fuel hedge value in the Companies' avoided energy rates. He explained that SCSBA Witness Burgess failed to realize that avoided fuel costs used in the avoided energy rate calculation represent the full price of the fuel that Duke would otherwise have purchased if the Companies were to generate energy themselves rather than purchasing fixed price QF power. He went on to explain that the objective of fixing avoided costs is to quantify the incremental cost of alternative energy that "but for the purchase from such [QF], such utility would generate or purchase from another source." Therefore, the fuel required to generate the equivalent amount of energy is the fuel being avoided. Moreover, Witness Snider explained that when prices are established in any avoided cost proceeding, they represent a price that QFs have an option to receive, while the Companies and their customers have an obligation to pay the QF at the QF's sole discretion. This arrangement essentially represents the QF owning a "Put Option" from the Companies and their customers because the QF has the right but not the obligation to sell its power to Duke. However, while the Companies and their customers have an economic obligation to purchase the QF power, they have no rights to deny purchase from the QF irrespective of prevailing market prices at the time of exercise. Witness Snider further testified that the Companies had not recommended a separate charge or reduction in the avoided energy rate to recognize this "put premium" to the QF. (Tr. Vol. 2, p. 630.30-31.)

Last, Witness Snider clarified that contrary to SCSBA Witness Burgess's statements, Duke had appropriately included avoided environmental costs, such as O&M costs to manage coal ash, in calculating the Companies' avoided energy rates. Specifically, Witness Snider testified that projected environmental costs associated with NO_x and SO_2 emissions, as well as coal ash handling costs at the existing coal units were included in the production cost model when calculating avoided energy rates. (Tr. Vol. 2, p. 630.32-33.)

In conclusion, Witness Snider recommended that the Commission reject SCSBA Witness Burgess's recommendations related to the Companies' avoided energy rate calculation, and accept the Companies' avoided energy rates as a reasonable calculation of the Companies' actual avoided energy costs. (*Id.*)

On surrebuttal, SCSBA Witness Burgess maintained his original positions regarding the Companies' avoided energy rates, but stated that Duke's explanation of why there were negative hours included in the production cost model made sense conceptually. He further stated that if there were no times when the transmission limit is reached within DEP-East and DEP-West, then the avoided energy rates should be equivalent. (Tr. Vol. 2, p. 787.12.)

During the evidentiary hearing, Mr. Burgess agreed that Duke's Hearing Exhibit No. 26 confirmed that the transmission constraints across the firm transmission between DEP-East and DEP-West had been reached only three times during the last five years, none of which had occurred within the last three years. He further agreed that the transmission limit was reached between DEP-East and DEP-West for a total of only four hours within the past five years, meaning there were no transmission constraints within DEP-East and DEP-West during 99.9% of that time. (Tr. Vol. 2, p. 806.)

<u>Commission Determination</u>

This Commission has previously approved Duke's use of PROSYM under the peaker methodology to calculate avoided energy rates. No party to this proceeding disputes the appropriateness of Duke's utilization of the PROSYM production cost simulation model to calculate avoided energy rates. SCSBA Witness Burgess states that "production cost models generally solve for the optimal unit commitment and dispatch to meet system load at least cost." ORS Witness Horii finds Duke's utilization of the model to be consistent with PURPA and Act 62. Therefore, it is appropriate for the Companies to continue calculating avoided energy rates under the peaker methodology utilizing the PROSYM production cost model.

In addition, the Commission finds the Companies' inputs and assumptions included in the production cost model to be reasonable and appropriate, as well as the Companies' resulting energy rate calculation. Mr. Horii, the ORS's expert consultant, reviewed the Companies' inputs and assumptions, and testified that based upon his investigation, the Companies' calculation methodology is consistent with PURPA and Commission precedent. ORS Witness Horii also testified that DEC's and DEP's avoided energy costs are a "reasonable result" of the Companies' calculations. (Tr. Vol. 2, p. 525.10.) The Commission finds merit in this testimony as well as Duke Witness Snider's testimony supporting and explaining the Companies' avoided energy rate calculations. In addition, although SCSBA took issue with the Companies' inputs and assumptions, and as explained in detail herein, Duke Witness Snider refuted each of SCSBA's claims, and SCSBA provided insufficient evidence in response to Duke's rebuttal to support its arguments that Duke's avoided energy inputs and assumptions were unreasonable. Therefore, the Commission finds and concludes that the Companies' avoided energy cost calculations, inputs, assumptions, and resulting avoided energy rates fully and accurately reflect the costs to be avoided from purchasing energy from QFs and should be approved.

<u>Negative Avoided Energy Hours</u>

In regard to SCSBA Witness Burgess's concerns regarding Duke's modeling of negative avoided energy hours, the Commission first notes that Mr. Burgess admitted in his rebuttal testimony that negative avoided energy hours included in Duke's model could actually represent "real-world" conditions on the Duke systems. On surrebuttal, SCSBA Witness Burgess also agreed that Duke Witness Snider's explanation as to why there were negative avoided energy hours included in the production cost model made "sense [] conceptually," and did not provide further evidence undermining Duke's explanation. Additionally, during the hearing and in response to questions from the Commission, ORS Witness Horii agreed that the inclusion of negative avoided energy costs to the production cost model could be attributable to the start costs for CTs, which aligned with Duke Witness Snider's explanation as to why negative avoided energy hours were included in the model. (Tr. Vol. 2, p. 606.) The Commission finds that SCSBA did not provide evidence supporting its contention that Duke erroneously modeled negative avoided energy hours, or refute Duke's reasoning for including negative avoided energy hours within the production cost model. While no model can completely match future conditions at the time QF energy is delivered, the Commission agrees with Duke that the precise operating conditions identified by SCSBA Witness Burgess are, in fact, "real world" operating constraints of Duke's generation fleet and transmission system, and are accurately represented in the model. Therefore, SCSBA's contention that Duke erroneously included negative avoided energy hours within the production cost model is rejected.

Modeling of DEP-East Marginal Cost

In response to SCSBA Witness Burgess's recommendation that the Companies be required to calculate separate avoided energy rates for DEP-East, the Commission finds persuasive Duke Witnesses Snider and Holeman's testimonies that Duke operates DEP-

East and DEP-West as a single Balancing Authority. The Commission agrees with Duke that because DEP-East and DEP-West are interconnected through firm transmission interconnects that allow integrated system dispatch of all fleet generating units in DEP-East and DEP-West to serve load in both Balancing Authority Areas, DEP's avoided energy costs reflect an avoided system cost across the full DEP Balancing Authority. Furthermore, on surrebuttal, SCSBA Witness Burgess recognized that the marginal unit to be avoided should be the same in DEP-East and DEP-West at least "the majority of the time," and also conceded that if there were no transmission constraints between DEP-East and DEP-West, then the avoided energy rate should be the same for each Balancing Authority Area. As presented in Duke's Hearing Exhibit No. 26, DEP-East and DEP-West have experienced no transmission constraints within the last three years, and have had no transmission constraints 99.9% of the time within the last five years. Power Advisory similarly found that Duke's avoided energy modeling "reflects system conditions" and that "there is not an issue that needs to be remedied." *Power Advisory Report*, p. 15.

Based upon all of the evidence presented on this issue, the Commission finds and concludes that DEP's quantification of a single avoided energy rate across the DEP Balancing Authority is appropriate and should be approved in this proceeding.

<u>Fuel Hedge Issue</u>

Duke's testimony explains that the utility and its customers are obligated to purchase a QF's output at the time the QF commits to sell to Duke under South Carolina's implementation of PURPA, while the QF is not obligated to sell its energy and capacity to Duke. The Commission agrees with Duke Witness Snider that the avoided energy cost developed to implement the "mandatory purchase" requirements of PURPA effectively represents a "Put Option" price to the QF that a QF owner has the option to receive. Based upon the evidence presented by Duke, it is clear that the Companies and their customers bear the purchase risk in the avoided cost arrangement. The Commission additionally finds persuasive the fact that the Companies' customers are just as likely to be exposed to cost increases as they are to cost decreases in locking into a 10-year fixed-term PPA, in a similar manner that they are exposed to cost increases and decreases when locking into a 10-year forward natural gas price contract.

Moreover, SCSBA has failed to provide sufficient evidence that renewable QFs actually do in fact provide a hedge to the Companies and their customers. SCSBA did not present detailed support for its position that renewable QFs produce a hedge to the utility nor did SCSBA Witness Burgess attempt to calculate a hedge value. The Power Advisory Report also does not identify this critique by Mr. Burgess in its independent evaluation of Duke's avoided energy costs. Therefore, the Commission agrees with Duke that the Companies' obligation to purchase power from renewable QFs does not provide a fuel hedge to the utility above Duke's actual, avoidable cost of energy and a fuel hedging adder should not be included in Duke's avoided energy rate calculations.

Environmental Cost Inputs Issue

SCSBA Witness Burgess's rebuttal testimony alleges that the Companies' avoided energy cost calculations fail to account for certain environmental costs of marginal generating units, including coal ash costs. The Commission finds Duke Witness Snider's direct and rebuttal testimonies persuasive and unrebutted that projected environmental costs associated with NOx and SO_2 emissions, as well as coal ash handling costs at existing coal-fired generating units are included in Duke's production cost model for purposes of fully and accurately calculating DEC's and DEP's avoided energy rates. SCSBA has provided no evidence to refute this fact and Witness Burgess does not further disagree with Duke's inclusion of avoided environmental costs within the avoided energy rate calculation in his surrebuttal testimony. The Power Advisory Report also does not identify this critique by Mr. Burgess in its independent evaluation of Duke's avoided energy costs. Therefore, the Commission finds and concludes that Duke has appropriately included environmental costs of marginal generating units within its avoided energy rate calculations, and that these associated inputs to Duke's production cost model should be approved.

Based upon the foregoing and all evidence in the record, the Commission finds and concludes that Duke's calculation of avoided energy rates and associated inputs and assumptions are reasonable and should be approved.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 11

The evidence in support of this finding of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Summary of the Evidence

Duke Witness Snider described the Companies' proposed avoided energy rate design, testifying that the marginal energy rate structure includes differentiation of summer, winter, and shoulder seasons and designates nine distinct energy pricing periods to reflect the energy value of QF generation during the different timeframes. Specifically, the summer energy season is defined to include June, July, August, and September; the winter energy season is defined to include December, January, and February; and the shoulder energy season is defined to include March, April, May, October, and November. He testified that the design reflects nine energy pricing periods to reflect the energy value of QF generation during the different time frames, and that the Schedule PP rate design appropriately compensates QFs for the avoided energy value they create for customers through the incorporation of granular seasonal and hourly rate periods. (Tr. Vol. 1, p. 58.26-27.)

Duke Witness Snider further testified that the hourly energy rate periods reflect the concept of including higher priced periods, called premium peak hours, in the Companies' winter and summer seasons. He stated that these premium peak hours provide the highest rates to incent generation during these hours when the value of the energy avoided by QF power is greatest for customers. Days with premium-peak and on-peak hours include Monday through Friday, excluding certain holidays. On-peak energy pricing has a defined set of PM hours during the summer period and both AM and PM hours during both the winter and shoulder periods. Off-peak hours within each season include all hours not otherwise defined as premium or on-peak, and include certain holidays. The hourly definitions for the nine pricing periods also vary slightly for DEC and DEP to account for the differences in each utility's load profile net of solar generation. (Tr. Vol. 1, p. 58.27-28.)

ORS Witness Horii testified that the Companies have updated the Standard Offer avoided energy rate designs by adding more hourly and seasonal granularity to more accurately reflect the hours when QFs provide energy value to the Companies. Based upon his review, Mr. Horii stated that the Companies' updates to the avoided energy rate design were a reasonable and consistent result of the Companies' utilization of the peaker methodology, and are consistent with PURPA and the Commission's prior approval. He therefore recommended no changes to the Companies' avoided energy rate design as proposed. (Tr. Vol. 2, p. 384.09-10.)

SCSBA Witness Burgess argued that the hours grouped within each pricing period as proposed by Duke are subjective and can be skewed to impact the prices paid to solar QFs, which are limited in the hours when they can produce electricity. In particular, he suggested that the Companies' off-peak hours are overly broad and include hours when solar generation would be available and that by grouping these hours in this manner, all of which have a lower than average cost for that season, that solar QFs are being disadvantaged. Witness Burgess argued that Duke had arbitrarily selected time periods that undervalue true daytime avoided costs, therefore biasing against daytime QF production such as solar power. (Tr. Vol. 2, p. 382.30-39.)

He further contended that in the "extreme case," avoided energy costs could even be priced on an hourly basis. He therefore suggested re-designating a certain number of these low cost of service hours into a separate pricing period so that the peak hours better coincide with solar generation operations. SCSBA Witness Burgess argued that his alternative avoided energy rate design offered distinctly more value to solar generators than the Companies' avoided energy rate design and could significantly affect solar compensation. (Tr. Vol. 1, p. 382.38-42.)

On rebuttal, Duke Witness Snider rejected SCSBA Witness Burgess's alternative avoided energy rate design as improperly focused on the specific operating characteristics of solar QFs while shifting compensation away from hours when the Companies and their customers see the most value for the energy delivered by the QF. (Tr. Vol. 1, p. 630.34.) In response to SCSBA's proposal, Witness Snider explained that the energy rate design should reflect the Companies' cost of service and system needs, as well as encourage QF generators to adjust their operation to maximize their production during hours that are most beneficial to retail customers, and therefore the system as a whole. He explained that the rate design hours must also be granular enough to provide clear price signals regarding the future value of generation to QFs, but not so specific that the defined pricing periods shift with the smallest movement in forecasted inputs. He testified that this balance is an important consideration to undertake when the rate design will remain in effect for multiple years under a fixed-price purchased power agreement. (Tr. Vol. 2, p. 630.38-39.)

In addition, Mr. Snider testified that the rate design must also be administratively manageable to ensure accuracy in billing while minimizing potential confusion amongst QFs caused by frequent price changes. In support of the Companies' proposal, he testified that the rate design fairly balances all considerations in a manner that appropriately reflects cost causation and offers QFs the opportunity to adjust their production hours to maximize their financial benefit, in addition to being administratively manageable from a metering and billing perspective. Duke Witness Snider concluded by stating that the proposed rate design also conforms with the fundamental indifference principle of PURPA, and ensures customers are not paying more than the actual costs avoided by the utility. (Tr. Vol. 2, p. 630.39-40.)

Commission Determination

The Commission finds merit in the general approach utilized by the Companies to develop granular pricing methods for avoided energy that more accurately reflect DEC's and DEP's highest production cost hours and loads, in order to increase the likelihood that the interests of ratepayers and developers of QF generators align. In addition, the Commission agrees with Duke Witness Snider that Duke's updated rate design strikes an appropriate balance between accurate avoided cost pricing and administrative efficiency. Duke Witness Snider's testimony provides reasonable support for the Companies' avoided energy rate design as following a methodological approach to evaluate system costs and impacts, in an effort to properly align price signals provided in the rate design with Duke's avoided energy costs.

With regard to SCSBA's proposal of an alternative rate design, the Commission finds that there is not sufficient evidence demonstrating that implementation of this additional/modified rate design proposal is appropriate for the standard offer or cost beneficial to Duke's customers. SCSBA's recommendation to provide additional pricing periods specific to solar QFs for the purpose of increasing a solar QF's revenue must be considered in light of the fact that the standard offer tariff is an optional tariff intended to be generically available to all small power producer QFs pursuant to 18 C.F.R. § 292.304(c) that are less than two megawatts in size. *See* Section 58-41-10(15). It must further be considered in light of the fact that PURPA requires non-discriminatory rates to be established for QFs, while customers should be left indifferent to the Companies' QF purchases. Further, the Commission finds that energy rate design should reflect the Companies' cost of service and system needs, as well as encourage QF generators to adjust their operations to maximize their production during hours that are most beneficial to retail customers and therefore, the system as a whole. This is supported by Act 62, which requires the Commission to treat small power producers on fair and equal footing with electrical utility-owned resources by ensuring that "rates for the purchase of energy and capacity fully and accurately reflect *the electrical utility's* avoided cost." *See* Section 58-41-20(B)(1) (emphasis added).

The Power Advisory Report identifies that Power Advisory performed independent analysis of the projected hourly avoided costs to assess the degree to which the avoided cost energy pricing periods appear to inappropriately bias the value of energy realized by solar QFs. Power Advisory's analysis suggested that there was a "modest underpayment for solar QFs under DEC's rates and overpayment under DEP's rates." Power Advisory therefore recommended that the Commission direct the Companies to provide appropriate analytical support for their avoided cost periods in subsequent filings. *Power Advisory Report,* p. 17. The Commission notes that Power Advisory does not recommend specific modifications to DEC's and DEP's avoided energy rate design be ordered in this proceeding, and the Commission adopts Power Advisory's recommendations that the Companies should provide additional analytical support for the avoided cost rate periods in future avoided cost filings. For purposes of the avoided cost rates authorized in these proceedings, however, the Commission finds the Companies' evidence supporting DEC's and DEP's avoided energy rate design will provide a reasonable and consistent price signal to QFs, encouraging them to align their generation with the time periods that have most value to customers.

Based upon the foregoing and all evidence in the record, the Commission finds and concludes that Duke's avoided energy rate design, as presented in the Companies' Joint Application, should be approved.

E. Calculating Avoided Energy Rates for Large QFs

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 12

The evidence in support of this finding of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Summary of the Evidence

In his direct testimony, Duke Witness Snider explained that the Companies plan to also use the peaker methodology to calculate avoided costs for larger, non-standard offer QFs. He testified that in using the peaker methodology for larger QFs, Duke updates the inputs used in performing the peaker methodology to most accurately reflect the costs avoided by the specific large QFs. In particular, he explained how the Companies will update projected fuel costs in the model to reflect the then-prevailing value of avoided fuel. He further explained how Duke will also use the actual load shape of the large QFs in modeling the avoided energy value as opposed to the generic baseload 100 MW generator used in the development of the Standard Offer rate. Witness Snider concluded his direct testimony by explaining how these adjustments for large QFs are consistent with PURPA and Act 62, both of which envision taking into account the actual attributes of the QF when calculating the avoided cost value created for consumers. (Tr. Vol. 1, p. 58.29-30.)

SCSBA Witness Burgess took issue with Companies' proposal to "take the specific supply characteristics or 'resource type' of the QF into account," including using a solar generation profile for solar QFs," in determining the avoided energy cost rate under the peaker methodology for non-Standard Offer PPA QFs. Witness Burgess therefore argued that, "avoided energy rates for each type of QF should be technology neutral." He also argued that the technology-specific approach for large non-Standard Offer solar QFs utilizing battery storage is inappropriate. In conclusion, he contended that Duke should treat all Standard Offer and non-Standard Offer QFs the same way under the peaker methodology, and for both of these QFs' avoided energy cost rates to be technology neutral. (Tr. Vol. 1, p. 382.30-32.)

In response to SCSBA Witness Burgess, Duke Witness Snider first pointed out that the Companies' intent in applying a solar-specific generation profile for solar QFs is to further ensure that the avoided energy rates calculated for non-Standard Offer PPA QFs most precisely equal the Companies' avoided cost, consistent with both PURPA and Act 62. He then agreed with SCSBA Witness Burgess that a solar QF with storage operating in a controlled manner that does not reflect the generator profile of an uncontrolled intermittent solar QF should be eligible for avoided energy rates calculated using a load-profile reflecting the characteristics of the storage device utilized by the QF. However, Witness Snider reiterated that Duke supports applying a solar-specific load profile to solar non-Standard Offer PPA QFs. (Tr. Vol. 2, p. 630.34-35.)

In support of Duke's proposal, Witness Snider explained that FERC's regulations governing the rates for purchase from QFs recognize a number of factors in 18 C.F.R. § 292.304(e) relating to the supply characteristics of the QF that should be taken into account "to the extent practical" in determining avoided costs. Specific to intermittent QFs, FERC has also more recently recognized that utilities may take the QF's supply characteristics into account, including, among others, the availability of capacity, the QF's dispatchability, the QF's reliability, and the value of the QF's energy and capacity. *Windham Solar, LLC*, 157 FERC ¶ 61,134 (2016). Witness Snider explained that FERC's statements also align with Act 62's provision that avoided cost methodologies approved by the Commission "may account for differences in costs avoided based on the geographic location and resource type" of the QF. *See* Section 58-41-20(B)(3). He additionally noted that the Commission had previously approved Dominion Energy South Carolina's proposal to calculate avoided energy rates based on a solar-specific load shape in May 2018. *Amended Order Approving Fuel Costs,* Order No. 2018-322(A) at 28, Docket No. 2018-2-E (May 2, 2018). Moreover, Witness Snider identified that other utility commissions, such as the Montana Public Service Commission, have also recently held that adopting a standard offer QF's avoided energy cost for QFs ineligible for the standard offer would be unjust and unreasonable to the utility's customers, since Larger QFs ineligible for the standard offer have individual and unique supply characteristics. (Tr. Vol. 2, p. 630.35-37.)

Last, Duke Witness Snider rebutted SCSBA Witness Burgess's concern that Duke may include methodological choices that have not been made transparent in this proceeding when calculating non-Standard Offer PPA QF's rates, by reiterating the specific supply characteristics that Duke plans to take into account when calculating such rates for large QFs. He explained that solar QFs or solar QFs with integrated battery storage will be required to supply an hourly energy production profile that will be used in place of the flat 100 MW no-cost generation profile that is used when calculating the standard offer avoided energy rates. Witness Snider additionally explained that, consistent with the Companies' historic practice, the Companies will also apply the most up-to-date inputs under the peaker methodology (such as updates to the fuel prices to reflect the current market value of fuel, as well as updates to reflect any changes to the Companies' resource plan to be consistent with the most recently-filed IRPs) in order to more accurately align the avoided cost rates paid to the QF with the value provided to customers. In conclusion, Witness Snider explained that these updates are transparent inputs to the model that can have the effect of raising the avoided cost value paid to the QF with equal likelihood as lowering the value paid to the QF. (Tr. Vol. 2, p. 630.36-37.)

Commission Determination

In Order No. 69, FERC explained that standard rates for purchase may differentiate among QF technologies on the basis of supply characteristics, while also recognizing that administrative efficiency of setting generic standardized avoided costs that do not take into account the specific characteristics of these small QFs is appropriate even if a deviation in value from true avoided costs results.

> (FERC) is aware that the supply characteristics of a particular facility may vary in value from that average rate set forth in the utility's standard rate required by this paragraph. If the Commission were to require individualized rates, however, the transaction cost associated with administration of the program would likely render the program uneconomic for this size of (QF).

Order No. 69, 45 Fed. Reg. at 12,223. In describing the avoided costs rates to be paid to larger QFs, FERC also emphasized that a QF's capacity and energy supply characteristics could be taken into account in analyzing whether the QF provided capacity value and in calculating the incremental energy value to be avoided by the QF. *Id*. at 12,224 (describing the specific capacity value considerations of wind, solar, and biomass QFs). FERC also established specific factors that could affect the rates for purchases from QFs, while emphasizing that the selection of a methodology setting avoided costs is best left to the State Commissions charged with implementing PURPA's must-purchase provisions. *Id*. at 12,226; see 18 C.F.R. § 292.304(e); *see also Windham Solar, LLC*, 157 FERC ¶ 61,134, at ¶6 (2016) (recognizing that the value of avoided energy and capacity could be lower for purchases from intermittent QFs than for purchases from firm QFs). Through Section 58-41-20(B)(3), Act 62 also incorporates consideration of several of these factors as a part of South Carolina's framework for establishing avoided cost rates. Moreover, as noted by Duke Witness Snider, the Commission has previously approved Dominion Energy South Carolina's use of a solar-specific load shape in calculating avoided cost rates. *Amended Order Approving Fuel Costs,* Order No. 2018-322(A), at 28, Docket No. 2018-2-E (May 2, 2018).

The Commission finds merit in the concept underlying the recommendation of Duke Witness Snider, that Duke's quantification of avoided costs for larger QFs should recognize the characteristics of the power supplied by the QF. Considering the factors in Section 58-41-20(B)(3) and the FERC regulations in the determination of avoided cost rates ensures that the Commission-determined avoided cost methodology remains true to

PURPA's directive that avoided cost rates are to be based on the costs that the utility actually avoids. Thus, the Commission recognizes that PURPA provides utilities with the ability to consider factors including the availability of capacity, the QF's dispatchability and reliability, and the value of the QFs' energy and capacity in establishing avoided cost rates for purchases from larger QFs, including solar QFs. *See* 18 C.F.R. § 292.304(e). The Commission also recognizes Duke's testimony pointing out that other utility commissions have similarly recognized that rates paid to larger QFs ineligible for the Standard Offer may take into account the specific characteristics of those QFs to most precisely calculate the utility's avoided cost. (Tr. Vol. 2, p. 630.35-37 *citing In the Matter of the Petition of Crazy Mountain Wind for the Comm'n to Set Certain Terms & Conditions of Contract Between Nw. Energy & Crazy Mountain Wind, LLC.*, No. 7505C, 2017 WL 1425719, at *6 (Apr. 18, 2017)). Accordingly, the Commission concludes that this approach complies with PURPA and Act 62.

In addition, the Commission determines that the purpose of Act 62 and FERC's regulations is to ascertain more specifically what a large, non-Standard PPA solar QF's actual avoided cost rate is. SCSBA Witness Burgess's assertion that a large, non-Standard PPA solar QF should have the same production profile as a generic Standard Offer QF in calculating avoided energy rates effectively requires the standard rate to apply to all QFs, contrary to Act 62's requirement that standard offer rates be made available to QFs less than 2 MW in size.

Contrary to SCSBA's position, the Power Advisory Report also recognizes the improved precision of calculating avoided cost rates for large QFs at the time of the request, which "ensures that the avoided cost rate reflects current assumptions and avoids the risk of stale avoided costs, which can be more significant for a large QF." Power Advisory further recognizes that "the avoided cost rate will reflect the specific operating profile of the large QF and result in a more reliable avoided cost rate." *Power Advisory Report*, p. 18. The Commission agrees with Power Advisory and Duke that these considerations are appropriate in applying the peaker methodology to calculate avoided cost rates for QFs above 2 MW not eligible for the Standard Offer.

Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate for DEC and DEP to take into account the production profile of the facility when calculating avoided cost rates for large, non-Standard PPA QFs. The Commission further finds that it is appropriate for DEC and DEP to continue the practice of applying the most up-to-date inputs under the peaker methodology in calculating such rates for large, non-Standard PPA QFs.

F. Avoided Capacity Quantification and Rate Design

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 13

The evidence in support of this finding of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Summary of the Evidence

Duke Witness Snider's direct testimony provided support for the Companies' avoided capacity calculation. His testimony began by explaining how avoided capacity costs are calculated under the peaker methodology. Witness Snider explained that one of the key elements in the application of the peaker methodology is determining the first year in which DEC and DEP each actually have a future avoidable capacity need. (Tr. Vol. 1, p. 13-15.) He further explained that a central tenant of PURPA is that customers are not required to pay QFs for avoided capacity unless the QF is actually offsetting a capacity need of the utility. Accordingly, the annual fixed capacity costs used in the avoided capacity rate calculation includes the annual fixed capacity costs starting with the first year in which an actual avoidable capacity need exists, as determined by the utilities' most recent IRPs. (Tr. Vol. 1, p. 58.14-16.)

Duke Witness Snider testified that DEC's projection of its first avoidable capacity need occurs in 2026, while DEP's first avoidable capacity need occurs in 2020, consistent with the Companies' 2019 IRP Update filings. He testified that accounting for the timing of needed capacity accurately values the capacity being delivered by the QF, consistent with PURPA's intent for the utility to estimate the costs that, but for purchase from the QF, would have otherwise been incurred by the utility and its customers. (Tr. Vol. 1, p. 58.14-17.) Last, he explained that under the levelized Schedule PP rate design, the avoided capacity payment is levelized to allow the QF to receive an avoided capacity payment in each year of the contract, as long as an actual capacity need exists at some point within the term of the avoided cost period. Put another way, the QF will receive capacity payments during each year of the contract, in order to credit the QF for future avoided capacity, so long as the utility has an avoidable capacity need within the avoided cost period. In conclusion, Witness Snider testified that the Companies' recognition of DEC's and DEP's need for capacity in the avoided capacity cost calculation is fair to both the Companies' customers and the QF. (Tr. Vol. 1, p. 17-18.)

ORS Witness Horii supported the method used by the Companies to calculate avoided capacity costs and stated that the method was one of the generally accepted methods for calculating PURPA avoided capacity costs used throughout the United States. (Tr. Vol. 2, p. 525.11.) He then testified that the lower avoided capacity rates calculated for DEC as compared to DEP were justified. In support of his position, Mr. Horii testified that the Companies' use of the recently filed 2019 IRPs was appropriate, reasonable, and transparent. In reviewing the Companies' load and resource balance table that DEC provided to ORS as the basis for its capacity need determination, ORS Witness Horii found that the increases of generation capacity via capacity increases or uprates in 2021 through 2024 did not require DEC to recognize avoided capacity costs in those years. (Tr. Vol. 2, p. 525.11-12.) He also agreed that although DEC's load and resource balance table identified the addition of the Lincoln combustion turbine ("CT") in 2025, DEC appropriately identified 2026 as the first year of avoided capacity cost, because the Lincoln CT has already been approved and commenced construction. Therefore, Mr. Horii explained that moving the first year of avoided capacity costs to 2025 instead of 2026 would incorrectly increase the avoided capacity payments to QFs, and recommended the Commission approve the Companies' first year of capacity needs as identified in DEC's and DEP's 2019 IRP Updates and used in calculating the Companies' avoided cost rates. (*Id.*)

In response to Duke's avoided capacity cost calculation and identified first year of need, SCSBA Witness Burgess argued that Duke's proposal was biased against QFs and underestimated capacity value in two ways. First, he argued that for DEC, Duke inappropriately assumed that each QF would provide zero capacity value from 2020 through 2026. Although he admitted that Duke's load and resource forecast do not project an internal resource need until 2026, he stated that Duke has the option to sell its excess capacity in the wholesale capacity markets and to receive commensurate compensation for doing so. (Tr. Vol. 1, p. 382.62.) He argued that the addition of QF capacity would further increase Duke's capacity position, allowing for greater off-system sales. He therefore recommended that the QF capacity provided to DEC between 2020 and 2026 be traded by DEC either bilaterally or into PJM's Reliability Pricing Model capacity market, and subsequently credited to Duke's customers, despite admitting that this capacity "may not be necessary to cover any internal capacity deficiencies." (Tr. Vol. 1, p. 382.62-65.)

Second, he argued that Duke incorrectly assumes that each QF provides zero capacity value after 2029. In support of his argument, he argued that new generation sources, such as gas peakers, have a project life of 30 years or more, and that the benefit to ratepayers of avoided capacity from QFs may extend well beyond the life of the proposed 10-year contract period. He argued that Duke's proposal limits the capacity component of QF contracts to 10 years, even though solar PV resources have a project lifetime of 20 years or more. He therefore concluded that there is "significant likelihood" that the capacity from these projects could be re-contracted at a later date. (Tr. Vol. 1, p. 384.65.) He further argued that since there would be no fuel costs, transport costs, and minimal

O&M costs, that the cost to re-contract these QFs would likely be very low compared to other options, providing a "meaningful option value." However, he concluded by stating that he did not recommend adjusting Duke's avoided cost methodology to reflect this option value at this time. (Tr. Vol. 1, p. 384.66.)

In response to SCSBA's first critique of the Companies' identified first year of need, Duke Witness Snider explained that from a legal perspective, utilities are not obligated to pay QFs for capacity that exceeds system needs, such as for resale in a capacity market under PURPA. In support of his contention, he stated that FERC has long held that "an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity…(the purchase) obligation does not require a utility to pay for capacity that it does not need." (Tr. Vol. 2, p. 630.54 (citing *City of Ketchikan*, 94 FERC ¶ 61,293 (2001) (citing *Order No. 69*, at P 30,865)).) Witness Snider further explained that FERC has also expressly stated that "there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements," as neither PURPA nor FERC's regulations require utilities to pay for the QF's capacity irrespective of the need for the capacity." *Id.* Further, he stated that FERC has more recently reiterated that "when the demand for capacity is zero, the cost for capacity may also be zero." (Tr. Vol. 2, p. 630.53-55 (citing *Hydrodynamics, Inc.,* 146 FERC ¶ 61, 193, at ¶ 35 (2014)).)

In response to SCSBA Witness Burgess's second critique, Witness Snider explained that it is prudent resource planning not to rely upon assumed future third-party owned capacity in years where no contract or other legally enforceable commitment guaranteeing delivery exists. He explained that QF owners have unfettered rights to make a business decision at the time their current PPA expires whether or not to enter into a new PURPA contract with the Companies or otherwise use (or not use) their facility in any lawful manner as they so desire. He explained that the Companies and their customers have no guarantee that the contracted facility will be physically capable of providing energy and capacity beyond the contract period for a variety of reasons. He stated that Duke's current and consistent position across numerous biennial IRP planning cycles has been to treat all wholesale purchase contracts the same and to recognize that a QF's legally enforceable commitment to provide energy and capacity extends only for the duration of its PPA. Further, he testified that Duke's position was fully consistent with FERC's implementing regulations, and that to presume a QF had made a commitment to deliver power to utility after its initial contract term ends would be inconsistent with PURPA. Witness Snider concluded by contending that SCSBA Witness Burgess' proposal is intended to advantage existing QFs over new QFs or other capacity resources, and is therefore discriminatory towards other traditional and non-traditional utility resources, in violation of PURPA's nondiscrimination principle. (Tr. Vol. 2, p. 630.56.)

On surrebuttal, SCSBA Witness Burgess did not refute Duke Witness Snider's claim that PURPA does not require utilities to pay QFs for capacity when there is no capacity need. Instead, Mr. Burgess questioned whether DEC's 2019 IRP reflected DEC's most current planning needs and requirements, arguing that it does not reflect DEC's planned accelerated retirements of five coal plants announced in DEC's September 30, 2019 North Carolina general rate case application after the 2019 IRP Updates were filed. (Tr. Vol. 2, p. 787.7.)

On cross-examination, Duke Witness Snider addressed the fact that DEC had recently announced the accelerated retirement of five coal plants after the 2019 IRP Updates were filed. He explained first, in terms of resource planning, a utility must make a determination or, “snap a chalk line,” at a certain point in time and use the most up-to-date inputs and assumptions available at that point in time in developing its integrated resource plan. Second, he explained that the planned accelerated retirement of the coal plants referenced by SCSBA Witness Burgess were subject to future regulatory determinations prior to DEC actually committing in an integrated resource plan to retire the units, as further evidence as to why those retirements were not included in the Companies’ 2019 IRP Updates. Mr. Snider specifically explained that Duke has sought authorization to adjust the depreciable lives of these plants in DEC’s now-pending North Carolina general rate case and, assuming the shorter depreciable lives are approved, that DEC would reflect this change in its 2020 IRP. (Tr. Vol. 1, p. 156-157) Last, he explained that although there was a possibility that these accelerated retirements could accelerate DEC’s first year of need to 2025, and therefore increase the avoided capacity rate, recognizing the accelerated retirements of these older coal units would also impact DEC’s marginal cost of energy thereby having the likely overall effect of lowering DEC’s overall avoided cost rates. This result would be due to the acceleration of more cost-effective and efficient generation replacing the units, which result he contended would be adverse to SCSBA’s interests. (Tr. Vol. 1, p. 163-164)

During SCSBA's examination of ORS Witness Horii at the hearing, Mr. Horii testified that he was unsure solar QFs could even meet the capacity need that would arise as a result of the five coal units being retired. He explained that during his experience, "if you retire a unit, you need to basically sort of put in a large () replacement capacity project. And, in that case, there may be no sort of avoided cost savings because you're not going to be avoiding or deferring that next capacity project because you're putting it in there to replace the massive amount of capacity that you've lost through the retirement." (Tr. Vol. 2, p. 550.) ORS Witness Horii further agreed that the retirement of these coal units could lower the Companies' proposed avoided energy rate. Last, ORS Witness Horii agreed with Duke Witness Snider's statement that it is a reasonable approach for a utility to select a specific point in time or to "snap a chalk line" in determining its resource plan and for purposes of calculating avoided cost rates. (Tr. Vol. 2, p. 550-551.)

Commission Determination

The Commission finds that DEC and DEP have appropriately identified their first avoidable capacity needs, as presented in their 2019 IRP Updates. ORS's expert Witness Horii testified that the Companies' use of the recently filed 2019 IRPs was appropriate, reasonable, and transparent, and the Commission finds merit in his testimony. Moreover, in regard to DEC's recently announced plans to accelerate retirement of certain coal units, the Commission finds that for purposes of this proceeding, it is reasonable not to consider those retirements in determining the DEC's first year of capacity for several reasons. As evidenced by Duke Witness Snider, it is necessary for the utilities to "snap a line in chalk" at some point in time for purposes of resource planning and calculating the Companies' avoided cost rates. ORS's expert Witness Horii agrees, and testified that this is a reasonable approach. Moreover, as also testified to by Duke Witness Snider, these five coal units have yet to receive the necessary regulatory approvals to be included in DEC's IRP as "committed" to these earlier retirement dates.

SCSBA's argument in support of including the prospective earlier retirement of the five coal units in DEC's calculation of avoided capacity costs was based upon the premise that including these retirements would accelerate the Companies' first year of capacity need, thereby increasing the avoided capacity rates approved in this proceeding to be paid to QF. However, Duke Witness Snider testified that consideration of the accelerated retirement of these five coal plants would not only affect the Companies' avoided capacity rate, but also the system production cost of energy used to quantify the avoided energy rate. He explained that most likely, the aggregate effect of accounting for these accelerated coal unit retirements would be an overall decrease in the Companies' avoided cost rates, based on the likelihood that retiring older coal units would drive down the avoided energy rate more so than any increase in avoided capacity. ORS's expert Witness Horii agreed that Duke Witness Snider's contention was plausible, and SCSBA provided no evidence suggesting otherwise.

The Commission also recognizes and appreciates Power Advisory's recommendation that DEC be required to adjust forward its first year of capacity need to 2025 to reflect the likelihood that these accelerated coal unit retirements become part of the DEC's resource plans. *Power Advisory Report*, p. 21. However, as discussed above, the Commission finds that it is appropriate and necessary to "snap a chalk line" in developing inputs and assumptions for calculating avoided cost rates, that the loss in avoided energy payments may more than offset the gain in avoided capacity payments to QFs by recognizing the accelerated unit retirement date assumptions, that the acceleration in unit retirement dates is subject to future regulatory determinations prior to DEC actually committing in an integrated resource plan to retire the units, and that if shorter depreciable lives are approved, that DEC will appropriately reflect this change in its 2020 IRP.

Based upon all of the evidence on this issue, the Commission finds and concludes that DEC's identified first capacity need in 2026 and DEP's identified first capacity need in 2020 are reasonable and appropriate for purposes of calculating avoided costs in this proceeding.

In regard to SCSBA's proposal to require the Companies to assume excess QF capacity can be sold into a wholesale capacity market prior to DEC's first year of capacity need in 2026, the Commission finds and concludes that such a requirement would be inconsistent with PURPA and contrary to FERC precedent. As cited to by Duke Witness Snider, FERC has held that "an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity…(the purchase) obligation does not require a utility to pay for capacity that it does not need." (Tr. Vol. 2, p. 630.54 (citing *City of Ketchikan*, 94 FERC ¶ 61,293 (2001) (citing *Order No. 69*, at P 30,865)).) FERC has also stated that "there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements," as neither PURPA nor FERC's regulations require utilities to pay for the QF's capacity irrespective of the need for the capacity." *Id.* FERC also reiterated in the

Hydronamics decision cited by Duke Witness Snider that "when the demand for capacity is zero, the cost for capacity may also be zero." (Tr. Vol. 2, p. 630.54 *citing Hydrodynamics, Inc.,* 146 FERC ¶ 61, 193, at ¶ 35 (2014).) PURPA therefore does not force a utility and its customers to pay for capacity that it otherwise does not need to serve customers. SCSBA Witness Burgess testified in his surrebuttal testimony that "he [does not] disagree with this position. (Tr. Vol. 2, p. 787.20.) The Power Advisory Report also generally accepts Duke's position on this issue. *Power Advisory Report*, p. 21. Therefore, the Commission agrees with Duke and the ORS that customers should not be required to pay solar QFs for capacity prior to the first year in which it is needed to serve system load and SCSBA's seemingly abandoned argument on this issue is rejected.

Based upon the foregoing and the entire record herein, the Commission finds the Companies' reliance upon the 2019 IRP Updates reasonable, and the resulting identified first years of need for DEC and DEP reasonable and appropriate as well.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 14-16

The evidence in support of these findings of fact are found in the verified Joint Application, pleadings, testimony and exhibits in theses Dockets, and the entire record in this proceeding.

Summary of the Evidence

ORS Witness Horii and SCSBA Witness Burgess each challenged certain aspects of Duke Witness Snider's calculation of avoided capacity cost under the peaker methodology. Duke Witness Snider testified that DEC and DEP each calculated their respective avoided capacity cost based on the cost of constructing new "peaker" combustion turbine ("CT") capacity. Duke relied upon publicly available CT cost data from the United States Energy Information Administration ("EIA"), which reflected the cost to build a single CT unit at a greenfield site. Duke then adjusted the EIA CT costs to recognize the economies of scale associated with shared land, buildings, roads, security, gas interconnection and other infrastructure for a 4-unit CT site, which Witness Snider testified aligned with the Companies' practice to build multiple units at a new site. (Tr. Vol. 1, p. 58.14-5.)

Issues Raised by ORS Witness Horii and Duke's Response

ORS Witness Horii recommended the Commission require DEC and DEP update the fixed charge rate component of the calculation, which is based upon the assumed economic life of the CT. Witness Horii testified that Duke uses an overly long 35-year economic life for the avoided CT, which spreads the capital-related costs of the CT over an excessive number of years. Witness Horii instead recommended a shorter 20-year economic life for the avoided CT, arguing that this 20-year period is commonly used in jurisdictions like California for calculating avoided costs, PJM for their Cost of New Entry report, and by the Lazard Levelized Cost of Energy Analysis report. (Tr. Vol. 2, p. 525.13-14.) Mr. Horii's recommendation would effectively increase the capacity cost customers pay for QF capacity by 29% for DEC and 30% for DEP over the capacity rates recommended by each of the Companies. (Tr. Vol. 2, p. 525.14, 18.)

In rebuttal, Witness Snider responded to ORS Witness Horii's recommendation to shorten the 35-year useful life relied upon in Duke's Fixed Charge Rate to 20 years by explaining that the 35-year useful life assumption is consistent with the assumptions in DEC's and DEP's 2019 IRPs. (Tr. Vol. 2, p. 525.14, 18.)

In his surrebuttal testimony, Witness Horii argued that even if the Commission accepted Duke's position that a 35-year economic CT life is appropriate that the Commission should still adopt Witness Horii's recommendation because Duke's 35-year CT fails to include sufficient major maintenance costs in the avoided capacity cost calculation to extend the life of the CT to 35 years. Witness Horii does concede, however, that Duke includes major maintenance costs in the avoided energy calculation but contends that this does not fully recognize these costs as being avoided by QF purchases. (Tr. Vol. 2, p. 528.4-5.)

During the hearing, Witness Horii testified that he found the cost of the avoided CT unit that Duke relied upon to be reasonable. (Tr. Vol. 2, p. 552.) Specific to the disagreement over whether it was appropriate to use a 20-year or a 35-year useful life, Witness Horii agreed with Witness Snider that Duke's approach reflects consistency with Duke's IRP, which assumes a 35-year useful life for CT units. (Tr. Vol. 2, p. 554.) Mr. Horii also could not identify any other utilities that similarly assumed the shorter 20-year useful life that he recommended for purposes of calculating avoided costs to pay to QF generators under PURPA. (Tr. Vol. 2, p. 555-556.) Mr. Hori also conceded that both the California avoided cost analysis and the PJM Cost of New Entry Study that he relied upon in his testimony were used as benchmarking analyses and were not—as is proposed here—used to fix a rate that will be paid by customers to compensate a generator for power. (Tr. Vol. 2, p. 559-560, 567.) Specific to the PJM Cost of New Entry Study, Mr. Horii accepted that the PJM capacity auction actually cleared 51 percent below the net cost of new entry unit underlying Mr. Horii's proposed 20-year useful CT life. (Tr. Vol. 2, p. 568, Ex. 18.) Mr. Horii also advocated that it was appropriate to keep the cost of the CT unit and its useful life assumptions consistent, and subsequently conceded that his proposal was inconsistent with Duke's approved 40-year useful depreciation lives that are used for ratemaking purposes. He also conceded that the impact of reducing Duke's current 40-year useful life of CTs for ratemaking to 20 years would increase base rates. (Tr. Vol. 2, p. 568-570.) Specific to the issue of whether Duke had appropriately included major maintenance costs as a component of avoided energy rates versus avoided capacity rates, Mr. Horii recognized that the PJM Cost of New Entry Study included major maintenance as part of the avoided energy calculation (Tr. Vol. 2, p. 576-580, Exhibit 17, p. 30, 31, 34.)

During the hearing, Mr. Snider commented that Duke believes Mr. Horii's use of the full Cost of New Entry unit to set an avoided capacity rate is not reflective of how PJM actually uses the calculated CT cost. In PJM, customers pay a bid price below the net (lower) Cost of New Entry unit's cost. Witness Snider explained that this results in Witness Horii overstating what customers should be paying. He further testified that he is not aware of any other jurisdiction that uses the Cost of New Entry concept to set an actual rate. (Tr. Vol. 2, p. 627-629.)

<u>Issues Raised by SCSBA Witness Burgess and Duke's Response</u>

SCSBA Witness Burgess argued that Duke's avoided CT unit cost was potentially biased against QFs and recommended a number of adjustments to Duke's avoided CT unit costs, each of which had the effect of increasing Duke's avoided capacity cost. (Tr. Vol. 1, p. 382.55-56.)

First, while Mr. Burgess found that the EIA's cost estimate for the F-Frame CT unit ($677/kW) represented a reasonable estimate, he argued that this type of unit does not necessarily correspond to the cost of the peaking unit that Duke would ultimately select to meet future peak demand or provide other services. (Tr. Vol. 1, p. 382.56, 58.) He argued that the increasing challenges of integrating solar into the Duke system may cause Duke to install more flexible peaking units that can better respond to the variable output of solar generation. Witness Burgess, therefore, recommended a significantly higher cost aeroderivative CT unit be taken into consideration, pointing out that an increasing number of more flexible aeroderivative CT units are being built in PJM. (*Id.*) He argued that consideration should be given to Dominion Energy Virginia's 2018 IRP estimate of the cost of an aeroderivative CT unit cost ($1,680/kW), and specifically recommended the Commission adopt a capital cost assumption of $1,178, representing the midpoint of the EIA F-Frame unit estimate, as relied upon by Duke, and the Dominion Energy Virginia aeroderivative CT unit estimate. (Tr. Vol. 1, p. 382.58.) Witness Burgess also opposed Duke's economies of scale adjustment, suggesting that constructing multiple CT units is not representative of what Duke is likely to build in the near term to satisfy its peaking needs. (Tr. Vol. 1, p. 382.58.)

Witness Burgess also argued that Duke's failure to include significant transmission system upgrade costs in the avoided CT cost estimate was not reasonable. Witness Burgess pointed to Xcel Energy Minnesota's 2016-2030 upper Midwest Resource Plan as estimating the capital cost of transmission associated with a new peaker (CT unit) to be $152/kW. Mr. Burgess did not adopt the Xcel Minnesota's Midwest IRP value, however, instead arguing that including $120/kW in transmission upgrade costs in Duke's avoided capacity cost calculation would be "more conservative." (Tr. Vol. 1, p. 382.60.)

In total, Mr. Burgess recommended that Duke's avoided CT costs be increased by 104%. (Tr. Vol. 1, p. 382.60.)[18]

In rebuttal, Duke Witness Snider responded that Mr. Burgess's recommendation to take the cost of an aeroderivative CT unit into consideration was unreasonable and that Duke opposed Mr. Burgess's recommendation to use the midpoint cost of the advanced F-Frame CT unit and the aeroderivative CT unit as arbitrary and inappropriate for a number of reasons. Witness Snider first highlighted that DEC and DEP both have numerous F-Frame CT units installed on their systems today and that Duke's 2019 IRPs show that DEC and DEP are both planning to build numerous F-class CT units in the future. (Tr. Vol. 2, p. 630.41-43.) He further testified that neither DEC nor DEP are currently projecting the need to build aeroderivative CT units. (Tr. Vol. 2, p. 630.43.) Witness Snider also pointed out that reliance on a higher cost aeroderivative CT unit is also not consistent with the peaker methodology, which is designed to quantify the cost of building the least cost peaker unit to provide incremental capacity and the system marginal cost of energy as reflecting the utility's full avoided cost. (Tr. Vol. 2, p. 630.44-45.) Witness Snider also explained that Mr. Burgess's rationale that Duke may need to install more

[18] SCSBA designated this percentage figure as confidential because it was derived from confidential CT cost information provided by Duke. Duke does not believe this figure needs to be confidential and Duke witness Snider filed it publicly in his rebuttal testimony. (Tr. Vol. 2, p. 630.49.) Duke agrees to its inclusion in the Commission's final Order as public information.

expensive aero-derivative CT units in the future to manage the intermittent output of must-take solar generators does not justify paying solar QFs higher capacity value. He explained that if Duke were to identify the need to install more expensive aero-derivative CT units, then the cost causer would be the solar providers and the incremental cost of constructing aero-derivative CTs versus F-class CTs should be paid by the solar providers and not paid for by customers to the solar providers. (*Id.*) Witness Snider also pointed out that Dominion Energy Virginia ultimately did not even include the aero-derivative CT in its final IRP and also did not recognize this type of unit as a proxy for the cost of capacity avoidable by the QF. (Tr. Vol. 2, p. 630.42, 45.)

Specific to Mr. Burgess's opposition to the economies of scale adjustment, Mr. Snider reiterated that the adjustment is fully consistent with Duke's practice of building multiple CT units at each power station. Mr. Snider further explained the reasonableness of Duke's approach by noting that Duke did not include any economies of scope adjustments despite the fact that Duke's IRPs also reflect Duke's plans to construct between two and eight CTs during a given year. (Tr. Vol. 2, p. 630.42, 45.) Witness Snider also identified that Duke provided extensive information to Mr. Burgess regarding the Companies' practices in response to SCSBA Interrogatory 3-9, which was introduced as Exhibit 5 during the hearing. (Tr. Vol. 2, p. 243-246.) Hearing Exhibit 5 validated Mr. Snider's position that eight of Duke's 11 power stations have four or more CTs and that Duke's consistent practice is to plan to build four or more generating units at a new greenfield power station site in order to create economies of scale. Therefore, Mr. Snider affirmed the economies of scale adjustment was appropriate. (*Id.*)

In response to Mr. Burgess's recommendation to incorporate transmission system network upgrade costs into the cost of the avoided CT unit, Mr. Snider explained that the EIA CT cost estimate appropriately included the interconnection costs of physically connecting the generation source to the transmission system. Interconnection costs are appropriately included because they are real costs that will be avoided when avoiding the construction of a new CT, and because the QF is fully responsible for the interconnection costs associated with its own facility. (Tr. Vol. 2, p. 630.48.) In contrast, he explained that the network system upgrade costs, proposed to be included by Witness Burgess were not appropriate as these significant transmission system costs may not be required to construct a CT and would also not be avoided by purchasing power from the QF. Witness Snider further explained that the concept of paying avoided transmission system upgrade cost to the QF generator would imply that the addition of non-firm generation on the system has deferred the need for system upgrades, which is not the case. (Tr. Vol. 2, p. 630.48-49.)

Duke Witness Snider concluded that SCSBA Witness Burgess's recommendation to increase the avoided capital cost assumptions for both DEC and DEP by 104% would more than double the capacity payments made by Duke's customers to solar QF providers in excess of the equivalent capacity cost that would otherwise have been incurred if the capacity would have been provided by the utility. Duke opposed this higher capacity cost as a subsidy to the benefit of the QF developer that would violate the fundamental indifference principle of PURPA and Act 62. (Tr. Vol. 2, p. 630.49.)

During the evidentiary hearing, Mr. Burgess conceded that the Commission should recognize the CT units that Duke actually plans to build on its system, which is the F-

Frame unit relied upon by Duke in calculating the avoided capacity cost. (Tr. Vol. 1, p. 430.) Witness Burgess further conceded that his proposed adjustment to include the cost of significant transmission upgrades was a judgment call and not based upon any analysis. (Tr. Vol. 1, p. 434.) He was also unaware of whether Xcel Energy's avoided cost rates included the same transmission network upgrade costs that Witness Burgess proposed to include for Duke and conceded that Dominion's significantly smaller $10.75/kW "transmission cost" could be comparable to Duke's inclusion of interconnection facilities cost. (Tr. Vol. 1, p. 433-434.)

<u>Commission Determination</u>

Based upon the foregoing and all evidence in the record, the Commission finds and concludes that Duke's quantification of the avoided capacity value under the peaker methodology is reasonable and should be accepted as filed. First, the Commission does not find ORS Witness Horii's argument that a 20-year useful life should be used in setting the Fixed Charge Rate input to the avoided peaker calculation appropriate. The Commission finds persuasive that Duke has applied economic life assumptions that are consistent with the assumptions in DEC's and DEP's 2019 IRPs for future utility-owned CTs, which would be the unit theoretically avoided by the QF purchase under the peaker methodology. Further, the Commission recognizes that both DEC's and DEP's depreciable life assumptions used in fixing base rates for utility owned assets are even longer at 40-years. This means customers are paying for utility-owned CT assets in base rates over 40 years. Recognizing that PURPA's objective is to keep customers indifferent between purchasing power from small power producers versus from traditional utility generation, the Commission finds that it would not be "just and reasonable to the ratepayers" of DEC and DEP, as required by Act 62 and PURPA, for the avoided capacity rates paid to QF generators to be calculated based upon the significantly shorter 20-year economic life assumptions recommended by ORS Witness Horii while the cost of Duke-owned CTs are spread over 40-years. As Witness Horii recognizes, shortening this useful life assumption in the Companies' base rates would increase costs for customers, which the Commission does not find to be reasonable or necessary at this time based upon the record in this proceeding. (Tr. Vol. 2, p. 568-570).

The Commission appreciates Witness Horii's efforts to identify credible support for his 20-year economic life recommendation, including the PJM Cost of New Energy study and California's quantification of avoided capacity costs used for energy efficiency program cost effectiveness and other non-PURPA uses in that jurisdiction. However, the record seems clear that neither of these sources are relied upon to fix a rate for purchasing power from a QF generating unit, as Mr. Horii recommends the Commission do here. Mr. Horii also explained that California does not pay QFs fixed forecasted avoided cost over 10 years as is now required by Act 62 in South Carolina. (Tr. Vol. 2, p. 560). Therefore, the Commission does not find the 20-year economic life assumption more appropriate than Duke's 35-year economic life assumption, which is consistent with DEC's and DEP's current resource planning assumptions.

The Commission similarly rejects Mr. Horii's recommendation that Duke should increase the major maintenance cost assumption in its avoided capacity cost calculation. The record supports that Duke is currently including major maintenance costs in the avoided energy rate calculation, which Mr. Horii agreed during the hearing is consistent with the PJM's approach in its Cost of New Entry Study, otherwise relied upon by Witness Horii. (Tr. Vol. 2, p. 576-580, Exhibit 17, at p. 30, 31, 34.)

The Commission similarly rejects SCSBA Witness Burgess's recommendations to significantly increase the avoided CT capital cost assumptions relied upon by DEC and DEP to calculate the avoided capacity costs. The Commission initially notes that the Power Advisory Report accepted Duke's proposed CT cost assumptions and rejected each of Mr. Burgess's recommendations to increase the avoided CT cost. *Power Advisory Report*, p. 19-20. The Commission finds that Duke has reasonably supported its use of the EIA-sponsored cost of the F-Frame CT in developing the avoided capacity costs under the peaker methodology. There is simply no basis to conclude that DEC or DEP are planning to construct aero-derivative CTs in the current 15-year planning period. Even if Duke were planning to construct such resources in the future, the Commission agrees with Duke and Power Advisory that the increased costs of constructing aero-derivative CTs would be caused by the intermittency and volatility of solar. It would therefore be inappropriate to pay solar generators based upon the higher capital cost of the aero-derivative CT in order to provide the capabilities needed to manage the operational challenges that intermittent and uncontrolled must take energy would be causing.

The Commission also finds that the record clearly supports Duke's proposed economies of scale adjustment both in terms of Duke's existing fleet as well as Duke's plans to install multiple new CTs in the future.

Finally, the Commission finds that Duke has reasonably included the facilities costs of interconnecting the CT unit to Duke's transmission system, and agrees with Duke and Power Advisory that including significant transmission system network upgrades is inappropriate in setting this generic avoided capacity cost value.

The Commission also notes that Duke has relied upon the same CT cost inputs and assumptions as also previously relied upon in calculating DEC's and DEP's avoided capacity costs in North Carolina.[19] As noted previously, the Commission has taken judicial notice of the NC Utilities Commission's *October 7, 2019 Notice of Decision*, which similarly found Duke's data related to the installed cost of a CT should be used in calculating avoided capacity rates. *October 7, 2019 Notice of Decision*, Finding Number 6, pg. 8.

<u>EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 17</u>

The evidence in support of this finding of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

<u>Summary of the Evidence</u>

Duke Witness Snider described the Companies' approach to determining the seasonal allocation weighting of capacity value used in the avoided capacity rate design. Mr. Snider explained that for DEC and DEP, seasonal allocation is now heavily weighted to winter based on the impact of summer versus winter loss of load risk, which has been

[19] For clarity, all adjustments and assumptions are consistent. However, Duke relied upon more current 2019 EIA CT cost inputs versus the 2018 EIA CT cost inputs used in North Carolina. (Tr. Vol. 1, p. 58.15.)

driven by the volatility in winter peak demands, as well as the growing penetration of solar resources and its associated impact on summer versus winter reserves. (Tr. Vol. 1, p. 58.19.) As presented in detail in the Solar Capacity Value study conducted by Astrapé Consulting and described in the Companies' 2018 IRPs, 100% of DEP's loss of load risk occurs in the winter and approximately 90% of DEC's loss of load risk occurs in the winter. Therefore, DEP's avoided capacity rates pay 100% of the future annual avoidable capacity value in the winter while DEC's new rates pay 90% of its annual capacity value in the winter and 10% in the summer period. (Tr. Vol. 1, p. 58.20-21.)

Witness Snider next identified the specific hours when QFs will provide capacity value, and explained that the Companies' Schedule PP capacity rate design offers three distinct pricing periods to accurately reflect the marginal capacity value to customers during each capacity period. Specifically, he testified that the pricing periods offer capacity payments during the PM hours in the summer months of July and August and both AM and PM hours in the winter months of December through March. He stated that the highest prices are paid in the early morning winter hours to recognize the greater loss of load risk and greater value of capacity during those hours. He concluded by stating that the pricing periods are designed to reflect the hours of DEC's and DEP's greatest capacity need and to ensure customers are paying QFs for providing capacity that actually reduces the utilities' needs for future capacity. (Tr. Vol. 1, p. 58.19-21.)

In response to Duke's proposed seasonal allocation, ORS Witness Horii first stated that the Companies correctly allocate the capacity costs based on the relative Loss of Load Expectation ("LOLE") in each time period. However, he recommended that the

Companies use the LOLE data from the "Existing plus Transition" case, rather than from the "Tranche 4 case," to determine the seasonal allocation and definition of capacity hours. (Tr. Vol. 2, p. 525.14.) Mr. Horii contended that the solar penetration levels of the "Existing plus Transition" case most closely resemble current levels of installed solar and the LOLE from that case would shift capacity allocation factors higher in the summer, and also change the allocation of capacity between winter morning and winter evening. Specifically, he recommended a 60% winter/40% summer weighting for DEC and 99% winter/1% summer allocation for DEP. (Tr. Vol. 2, p. 525.15-16.)

SCSBA Witness Burgess argued that the Companies' seasonal allocation of capacity value was "incorrect and "biased against solar QFs" and Mr. Burgess instead contended that the Companies should shift capacity payment hours from Winter AM to Summer PM hours. In support of his claim, Mr. Burgess criticized some of the assumptions in the Solar Capacity Value Study including the underlying load forecasts, differences in the availability of demand response in winter and summer months, and characterization of neighboring utility capacity support. Mr. Burgess also listed seasonal variations in assumptions for forced outage rates and planned maintenance as a biased assumption, but failed to expand on his concerns with that issue. (Tr. Vol. 1, p. 382.49-54.)

Specific to the Companies' underlying load forecasts, SCSBA Witness Burgess argued that the Solar Capacity Value study does not properly take into consideration how load and the resulting allocations might shift over time. In regard to the Companies' demand response programs, SCSBA witness Burgess argued that Duke incorrectly assumes only half of the demand response resources available in summer are available in winter. Although he stated that "this may be a reasonable assumption based on current demand response contracts and availability, a more concerted effort by Duke to target and mitigate extreme winter peak events could shift the balance of these resources towards winter and the resulting seasonal allocation towards summer." (Tr. Vol. 1, p. 382.49.) He further stated that he could not determine the hypothetical impact additional winter demand response resources would have on the seasonal allocation results by arguing that Duke did not provide him the necessary information to fully evaluate his hypothetical alternative demand response scenario. (Tr. Vol. 1, p. 382.50.) In regard to neighbor assistance, Witness Burgess argued that DEC and DEP are neighbors to several summer peaking utilities that may have available resources to contribute to winter peaking needs, and that greater summer capacity allocation may be artificially limited in Duke's modeling due to assumed transmission constraints. Last, SCSBA Witness Burgess argued that based upon his review of historical load data for DEC and DEP, the seasonal allocations do not make sense. He therefore recommended a different seasonal allocation from Duke's proposal, specifically that DEP's seasonal allocation reflect a 77% summer and 23% winter allocation, and DEC's seasonal allocation reflect a 82% summer and 18% winter seasonal allocation. (Tr. Vol. 1, p. 382.51-52.)

SACE/CCL Witness Wilson's testimony provided general critique of the Companies' 2016 Resource Adequacy study and 2018 Solar Capacity Value study, documented in Exhibit B to his testimony. He argued that his Exhibit B shows that the risk of very high loads under extreme cold was significantly overstated in the 2016 Resource Adequacy study, primarily due to the faulty approach Astrapé Consulting used to extrapolate the relationship between temperature and load to very low temperatures. He argued that winter resource adequacy risk was also overstated due to the demand response and operating reserve assumptions applicable to winter peak conditions. Moreover, he argued that both winter and summer risk were further overstated due to the economic load forecast uncertainty assumptions, which greatly overstate the risk of large and unexpected increases in peak load. He also contended that the Companies' approach to estimating seasonal, monthly and hourly resource adequacy risk, seasonal capacity values of solar resources, and recommended reserve margins will be highly sensitive to various assumptions that can change dramatically over just a few years. SACE/CCL Witness Wilson recommended that the Companies' seasonal allocation be rejected, but failed to propose any alternative seasonal allocations. (Tr. Vol. 2, p. 495.1-7.)

In response to SCSBA's first argument that the Companies should shift capacity payment hours from Winter AM to Summer PM, Duke Witness Snider testified that such a shift in capacity payment hours would unfairly benefit solar QFs at the expense of the Companies' customers and be in violation of PURPA's indifference principle. Witness Snider then rejected SCSBA Witness Burgess's claims regarding the reasonableness of the Companies' Solar Capacity Value study, explaining first, in regard to load forecasts, that the Companies' best estimate of the value of incremental QF solar capacity is reflected and validated by the Solar Capacity Value study's results. Mr. Burgess's argument, on the other hand, requests the Companies to make arbitrary assumptions of potential future changes to seasonal capacity needs in order to benefit solar QFs, which would additionally send improper price signals to QFs regarding the timing and need for QF capacity and energy. Mr. Snider testified that accepting Mr. Burgess's proposal would be both unreasonable and inappropriate. (Tr. Vol. 2, p. 630.64-73.)

Regarding SCSBA Witness Burgess's arguments concerning the Companies' demand response programs, Witness Snider first explained that the study requested by Mr. Burgess was for the Companies to run a hypothetical scenario assuming winter demand response had somehow increased to the same level as summer demand response, which is simply not the case. Duke therefore declined to run the hypothetical assumption assuming untrue facts regarding the Companies' demand response program capabilities. In support of this assertion, Witness Snider explained that Duke's actual program experience has evidenced that winter residential demand response program "potential" is more difficult to achieve than summer potential and listed several specific reasons. For instance, most winter demand response programs require in-home customer appointments, whereas summer demand response programs do not. He therefore concluded that it is not appropriate to pre-assume an unreasonable amount of winter demand response can be achieved, as advocated for by SCSBA, or this hypothetical winter demand response impact on avoided cost rates at this point in time. For the same above-explained reasons, Witness Snider also rejected SACE/CCL Witness Wilson's similar critique of the Companies' winter demand response. (Tr. Vol. 2, p. 630.69-73.)

Duke Witness Snider also rebutted SCSBA's criticisms regarding neighbor assistance, stating that these critiques were inaccurate and explaining that the Solar Capacity Value study included comprehensive modeling of the load, resources, and transmission capability of neighboring utilities. Last, he responded to SCSBA's arguments related to Mr. Burgess's review of historical load data for DEC and DEP. Although SCSBA had not yet responded to a data request requesting Mr. Burgess' exact calculations, Witness Snider testified that he most likely failed to account for the impact of must-take solar output in his analysis, and incorrectly included an extremely broad number of hours. Therefore, SCSBA Witness Burgess's review of the data was incorrect. In sum, Mr. Snider rebutted SCSBA's critiques of the Companies' seasonal allocation and rejected their alternative, and incorrectly calculated seasonal allocation. (Tr. Vol. 2, p. 630.72-73.)

In response to SACE/CCL Witness Wilson, Duke Witness Snider testified first, that Witness Wilson's testimony relied heavily upon his past assessment of the Companies' 2016 Resource Adequacy study and 2018 Solar Capacity Value study. He explained that since 2016, the Companies, Astrapé, and the NC Public Staff have worked to resolve outstanding concerned related to the 2016 Resource Adequacy study. Specifically, Witness Snider testified that concerns related to the correlation of load and extreme cold temperatures were already previously resolved with the NC Public Staff. Regarding SACE/CCL Witness Wilson's concerns with the Companies' operating reserves assumption, Witness Snider testified that Mr. Wilson was incorrect in his assertion and that Duke had already previously demonstrated that Mr. Wilson's assertion was incorrect in several North Carolina proceedings. He further testified that adopting Wilson's recommendations related to economic load forecast would only serve to lower the reserve margin requirement but would not have any impact on the allocation of LOLE or the Companies' rate design. If anything, a lower reserve margin could push out the date of the first capacity need for each utility, an outcome that would increase reliability risk and reduce capacity payments for QFs. Last, Witness Snider disagreed with Mr. Wilson's conclusion that the Companies should strive for price signals that are likely to remain reasonably stable as conditions change. In conclusion, Mr. Snider noted that Mr. Wilson had not proposed an alternative seasonal allocation, and recommended the Commission reject his incorrect critiques regarding the Companies' proposal. (Tr. Vol. 2, p. 630.70-79.)

In response to ORS Witness Horii's recommendation to use LOLE data from the Existing plus Transition case, Duke Witness Snider provided support for the Companies' utilization of LOLE data from the Tranche 4 case. He explained that given that Tranche 4 level of solar resources is mandated by existing North Carolina legislation, it is appropriate to price solar procured under the Standard Offer in this proceeding as incremental to Tranche 4 level of solar. He further explained that pricing solar based on lower Existing plus Transition solar would essentially result in a double counting and overpayment for QF solar by the Companies' customers. Witness Snider went on to testify that after taking into consideration the fully contracted MW acquired in CPRE Tranche 1, the estimate of existing and fully contracted solar for DEC is approximately 1,400 MW, which is expected to rise as current contracts under negotiation are executed. (Tr. Vol. 2, p. 630.58-62.)

In his surrebuttal, ORS Witness Horii responded that since his initial testimony, he had since determined that nearly 100% of projects with signed interconnection agreements and PPAs have resulted in completed in-service projects over the past three (3) years. He therefore modified his recommendation to reflect more "current conditions" for avoided cost purposes, and updated his alternative seasonal allocation proposal to be based upon the "Tranche 1" scenario as opposed to the "Existing plus Transition" scenario. Accordingly, he updated his alternative seasonal allocation for DEC to recommend a 30% summer and 70% winter allocation. His recommendations of 1% summer and 99% winter allocation for DEP remained unchanged. (Tr. Vol. 2, p. 528.8-9.)

SCSBA Witness Burgess's surrebuttal testimony stated that he agreed with Duke's critiques of his initial historical load analysis included in his rebuttal testimony, though with qualifications. He stated that to address the issues in his analysis identified by Duke, he would first update his analysis to reflect net load (rather than just load) by adjusting the historical load profiles to account for must-take solar output. To address the second issue—that he incorrectly included an extremely broad number of hours by using the top 5% of load hours—he testified that he adjusted the number of hours in his seasonal allocation proposal to reflect a narrower band of top load hours. Mr. Burgess then proposed a new seasonal allocation based upon an updated historical load analysis integrating the two aforementioned changes. His updated seasonal allocation proposed a 58% summer and 42% winter allocation for DEC and a 4% summer and 96% winter allocation for DEP. In addition, he argued that Duke should provide SCSBA a hypothetical analysis assuming Duke's winter demand response was higher, stating that the purpose of this hypothetical analysis is simply intended as a sensitivity case to see what the effect would be on the Companies' seasonal allocation. (Tr. Vol. 2, p. 782.22-24.)

<u>Commission Determination</u>

The Commission finds that Duke's reliance on Loss of Load Expectation is appropriate in the context of determining when a QF can help a utility avoid or defer a planned capacity addition, as agreed upon by ORS's expert Witness Horii. The Commission notes that in addition to agreeing with Duke's reliance on LOLE data, ORS Witness Horii otherwise agreed with every aspect of Duke's seasonal allocation, except for Duke's use of the "Tranche 4" solar data. Therefore, consistent with ORS's recommendation, the Commission supports the LOLE methodology underlying Duke's proposed seasonal allocations as reasonable and appropriate. The Commission, however, agrees with Duke's use of the "Tranche 4" solar data and rejects Mr. Horii's updated recommendation to base the Companies' seasonal allocation on "Tranche 1" installed solar assumptions. Specifically, the Commission agrees with Duke Witness Snider that the Companies' mandatory purchase obligations under existing laws are not avoidable and should be taken into consideration when determining seasonal allocation.

The Commission notes that Power Advisory recommends the Commission adopt Mr. Horii's recommendation. *Power Advisory Report*, p. 26-27. However, the Commission finds that for the same reason that the Companies' mandatory renewable energy procurement requirements under existing laws are not avoidable, the Commission finds that Power Advisory's recommendation on this issue should not be adopted. The Commission finds that Duke's position as presented by Witness Snider is more reasonable for the reasons discussed above.

Furthermore, while not affecting our decision on this matter, the Commission notes that the seasonal allocation hereby approved for QFs in South Carolina is consistent with the North Carolina Utilities Commission's recently issued *Notice of Decision* establishing avoided costs for QFs in North Carolina. *North Carolina Utilities Commission October 7,* *2019 Notice of Decision*, Finding Number 3, pg. 8.[20] The Commission finds that promoting consistency in the future seasonal allocation of capacity need that QFs can avoid is an appropriate objective in light of the fact that DEC and DEP plan and operate their systems across both states and that QFs installed in both States will avoid future capacity needs for all of DEC's and DEP's customers, whether located in South Carolina or North Carolina. Therefore, the Commission finds DEC's 10% summer and 90% winter allocation and DEP's 0% summer and 100% winter allocation appropriate, and concludes these allocations should be approved.

Turning to SACE/CCL Witness Wilson's concerns, the Commission finds merit in Duke Witness Snider's testimony that the Companies have previously worked with the North Carolina Public Staff in response to SACE/CCL's concerns over the relationship between winter load and cold temperatures. As Duke Witness Snider testifies, the NC Public Staff was satisfied that the approach taken to capture the correlation of load and extreme weather was reasonable, and, similarly, ORS's expert Witness Horii takes no issue with Duke's approach. The Commission also finds significant that, despite SACE/CCL Witness Wilson's arguments, neither the NC Public Staff or the North Carolina Utilities Commission concluded that changes were needed to DEC's and DEP's seasonal allocation of capacity value, as described above.

In regard to the assumptions made by Duke concerning the availability of winter demand response programs, the Commission agrees with Witness Snider that significant

[20] The Commission took judicial notice of the North Carolina Utilities Commission's recent assessment of Duke's avoided capacity and energy costs in North Carolina at the outset of the hearing. (Tr. Vol. 1, p. 15-17.)

differences can exist between portfolios of demand response programs targeting summer and winter capacity. The Commission finds Duke's assumptions regarding seasonal allocation to be reasonable and appropriate for purposes of inclusion in the avoided capacity rate, and therefore rejects SCSBA Witness Burgess's and SACE/CCL Witness Wilson's critiques concerning the Companies' demand response assumptions.

The Commission appreciates that SCSBA Witness Burgess's assessment of historical loads may have some relevance to Duke's proposed seasonal allocation of future capacity need; however, the Commission finds that the recently-installed and significant penetrations of solar in DEC's and especially DEP's service territories have different impacts on summer versus winter loads net of solar contribution than in the past. The Commission agrees with Duke Witness Snider that an assessment of historic loads without consideration of the impact of current and projected levels of solar output does not provide a complete or reasonably accurate picture of the appropriate seasonal allocation weightings to assign to forward-looking avoided cost rates. The Commission further agrees with Duke and the ORS Witness Horii that the use of the loss of load risk values to establish seasonal allocation factors is appropriate, and properly aligns with cost causation principles. In addition, the Commission agrees that these factors change over time, and that it is appropriate that the resource adequacy studies, along with all inputs and modeling assumptions, should be updated for use in future IRP filings and considered in future avoided cost proceedings. The Commission therefore rejects SCSBA's concerns regarding the Companies' underlying Solar Capacity Value study.

The Commission also agrees with Duke Witness Snider that SCSBA Witness Burgess's alternative seasonal allocation proposal would unfairly benefit solar QFs at the expense of the Companies' customers. Having found Duke's proposed seasonal allocation appropriate, the Commission finds that Duke's capacity payment hours are appropriately developed to incent QFs to provide power when customers need it the most, and accepts and finds it reasonable that these hours may (or may not) align with when solar QFs provide power to the system. The Commission therefore rejects SCSBA Witness Burgess's alternative proposal.

Based upon the foregoing and all evidence in the record, the Commission finds and concludes that DEC's 10% summer and 90% winter allocation and DEP's 0% summer and 100% winter allocation is reasonable and should be approved. The Commission also accepts Duke's LOLE methodology underlying the seasonal allocations as reasonable.

G. Solar Integration Services Charge

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-22

The evidence in support of these findings of fact are found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Summary of the Evidence

To ensure that small power producers are treated on a fair and equal footing with electrical utility-owned resources, this Commission is tasked with ensuring that each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment. *See* S.C. Code Ann. § 58-41-20(B)(3). DEC and DEP have quantified their avoidable energy and capacity costs by applying the peaker methodology as discussed earlier in this Order.

Duke Witness Snider also testified that, in conjunction with developing the Companies' forecasted avoided cost of energy and capacity under the peaker methodology, DEC and DEP commissioned a study of the incremental ancillary services costs of integrating intermittent QF solar into the DEC and DEP systems. (Joint Application, p. 13-15; Tr. Vol. 1, p. 58.30-35.)

Witness Snider explained that Duke had commissioned Astrapé Consulting in late 2017 to analyze the impacts of integrating solar into the DEC and DEP systems at varying solar penetration levels. He stated that Astrapé quantified the cost of utilizing the DEC and DEP conventional fleets to provide the additional operating reserves or generation "ancillary services" needed to reliably integrate the various levels of intermittent solar generation. (Tr. Vol. 1, p. 58.34-35.)

Duke Witness Wintermantel testified in support of the Astrapé Solar Ancillary Services Study ("Astrapé Study"). He began by describing the integration challenges utilities experience as solar penetration increases on the utilities' systems. As solar penetration increases, the uncertainty and intra-hour volatility in net load increases, meaning 5-minute deviations in net load can be much more significant in systems with high penetrations of variable and intermittent solar as compared to systems with no solar. To manage the increase in intra-hour volatility, additional load following operating reserves are required to allow generators additional flexibility to meet these unexpected movements in net load, which thereby increase ancillary services cost. In addition, Witness Wintermantel stated that generators are forced to start more frequently causing additional startup and maintenance costs. (Tr. Vol. 1, p. 302.2-9.)

Witness Wintermantel then provided an overview of the Astrapé Study explaining how Astrapé's Strategic Energy Risk Valuation Model ("SERVM") commits DEC's and DEP's resources on week-ahead, day-ahead, and hour-ahead basis and dispatches resources to load on a five-minute time step. For each year simulated, total production costs are then calculated and reported as well as the reliability metrics of the system. To analyze the economic impact of integrating solar, Witness Wintermantel testified that the SERVM model, which was similarly used in the Companies' Commission-approved 2012 and 2016 Resource Adequacy studies, modeled the Companies' system reliability with and without solar at various penetration levels. Witness Wintermantel's direct testimony explained that this modeling analysis was performed for the 2020 study year across several solar penetrations including a No Solar scenario, Existing plus Transition scenario (840 MW in DEC and 2,950 MW in DEP), Tranche 1 solar scenario (1,520 MW in DEC and 3,110 MW in DEP), and a significantly higher Plus 1,500 MW solar penetration scenario (3,020 MW in DEC and 4,610 in DEP). Once the ancillary services required to integrate these solar resources were determined, the costs of the ancillary service were also computed through the SERVM model. (Application, p. 14-16; Tr. Vol. 1, p. 302.09-15.)

Witness Wintermantel explained that an important aspect of the Astrapé Study is that SERVM is designed to recognize that utility system operators will have imperfect knowledge of day-ahead net load, net load a few hours ahead, and intra-hour net load to make generation commitment decisions. This imperfect knowledge is accounted for by incorporating load and solar forecast error, meaning the model commits its conventional generation fleet to a net load that has some level of error and then must adjust accordingly in real time, similar to the way system operators must adjust in real time. In order to mimic the movement of load and solar on a five-minute basis, the SERVM model requires one year of five-minute load and solar data as an input. For both DEC and DEP, the Astrapé Study used historical five-minute load and solar data from the 12-month period between October 2016 – September 2017. Mr. Wintermantel explained that the five-minute data was scrubbed for reporting anomalies or errors and the volatility embedded in these five-minute profiles was applied to the load and solar for each penetration analyzed. (Tr. Vol. 1, p. 302.9-13.)

After providing background on the Astrapé Study's inputs and modeling framework, Witness Wintermantel explained that the underlying premise of the Astrapé Study is to ensure that the operating reliability of the DEC and DEP systems is the same before and after additional solar is added to the Companies' systems. To study the impact on system reliability with and without solar, Astrapé utilized the $\text{LOLE}_{\text{FLEX}}$ metric of 0.1 within the model to measure the number of loss of load events due to system flexibility constraints, calculated in events per year. Mr. Wintermantel explained that $\text{LOLE}_{\text{FLEX}}$ as used in the SERVM model is a measure of the system's ability to satisfy net load obligations assuming that net load is known five minutes before it materializes, and provides a means of measuring if the system has enough load following reserves. As additional solar is added to the system, load uncertainty and intra-hour volatility increase, causing $\mathrm{LOLE_{FLEX}}$ to increase. In order to maintain the same reliability on the system as before the solar was added, load following reserves needed to be increased. Witness Wintermantel testified that the Study determines the appropriate amount of load following reserves to add by forcing the system back to the original $\mathrm{LOLE_{FLEX}}$ metric of 0.1 events per year. (Tr. Vol. 2, p. 302.14-18.)

Witness Wintermantel testified that at the Existing plus Transition solar penetration level for DEC, the Astrapé Study determined that an additional 26 MW of load following reserves were required to integrate 840 MW of solar. For DEP, the Astrapé Study identified that 166 MW of additional load following reserves were required in order to integrate 2,950 MW of solar. He then explained that based upon the results of the Astrapé Study, Duke included a $1.10/MWh Integration Services Charge for DEC and a $2.39/MWh Integration Services Charge for DEP be applied to solar generators committing to deliver power in the future. Mr. Wintermantel concluded that in his expert opinion, the Companies had appropriately used the results of the Astrapé Study to establish reasonable Integration Services Charges for DEC and DEP, respectively. (Application, p. 13-14, Tr. Vol. 1, p. 302.3.18-3.25.)

Duke Witness Wheeler's direct testimony supported the Integration Services Charge average cost rate design, explaining that all intermittent generation resources create this higher cost of service, not just new generation resources. In contrast, designing the charge to collect the incremental cost would result in preferential pricing for the first entrants while shifting cost recovery to new Sellers. Witness Wheeler opposed this incremental cost approach, explaining that it would be equivalent to only charging generation cost to new retail customers that cause the need for a new generator while allowing all existing customers to benefit from greater resources, which is potentially discriminatory and inconsistent with average-cost ratemaking principles. Witness Wheeler also testified that collection of incremental cost requires creation of vintage years for each participant, creating an administrative burden as projects get delayed or as existing projects PPAs expire and they enter into new agreements. He explained that collection of average costs eliminates these concerns and ensures that Sellers causing the ancillary services costs to be incurred properly pay the costs, thereby avoiding a cost shift to retail customers. (Tr. Vol. 1, p. 260.27-28.)

ORS Witness Horii testified that in his own modeling at E3, E3 had seen that increasing amounts of solar and wind generation can require additional ramping capability and reserves to meet both the intermittent nature of solar and wind generation and the diurnal ramping characteristics of solar generation. Based upon his review, he testified that the Companies' analysis is an acceptable approach to estimating solar integration costs. He did have two primary observations, which were that results of the Astrapé Study may indicate higher solar integration costs than would be required if the Companies sought to minimize those integration costs, and that the Companies' proposed to use the average integration costs, as opposed to incremental integration costs in applying the charge. However, he ultimately recommended that the Companies' solar Integration Services Charges of $1.10/MWh for DEC and $2.39/MWh for DEP be approved (Tr. Vol. 2, p. 525.19.)

In addition, Mr. Horii recommended the Companies' proposed charges be adopted as upper limits for solar Integration Service Charges for contracts signed under the Standard Offers. He testified that the Companies should conduct additional integration studies, and if lower incremental integration services charges were to be adopted for future offers, the integration services charges for this vintage of Standard Offer contracts should be updated to reflect those lower values starting with the effective date of the new offers. As part of the update, he testified, the Companies should be required to conduct technical workshops to gain input from the solar community and other stakeholders. (Tr. Vol. 2, p. 525.24-25.)

In response to ORS Witness Horii's recommendations, Duke Witness Snider stated that the Companies agreed that a technical workshop facilitated by the ORS and involving independent third-party consultants like Mr. Horii may better support an accurate review and quantification of an updated SISC. (Tr. Vol. 2, p. 630.86.)

In his surrebuttal, Mr. Horii testified that ORS preferred that E3 not facilitate the technical workshop as ORS is a statutory party to the Commission's proceedings to review the Companies' avoided costs and may elect to recommend changes to the Companies' calculation of future integration services charges. (Tr. Vol. 2, p. 528.15.)

SCSBA Witness Burgess had several concerns regarding Duke's proposed solar Integration Services Charge. First, he argued that it was premature to impose a SISC. He next argued that the analytical model Duke had used to support the proposed SISC had several flaws that likely exaggerate the projected cost of integration services. Third, he argued that there is little evidence in South Carolina that the magnitude of integration costs projected by Duke will materialize soon due to incremental solar deployment. Mr. Burgess then testified that Duke's proposal is incomplete since it only considers integration costs and not integration services that solar QFs could provide. Last, he argued that the proposed SISC is linked to a hypothetical model rather than real-world costs and introduces unnecessary uncertainty that would stymie solar QF project development.

SACE/CCL Witness Kirby testified that he had four main concerns with the Astrapé Study methodology. First, he argued the Astrapé Study relied on a manufactured metric that does not accurately reflect the actual reliability standards the utility must meet in its day-to-day operations. Second, he argued that the Study improperly scaled solar plant intra-hour output variability, also resulting in the calculation of excessive reserve requirements and charge. Third, he stated that the imposed higher reserve requirements in 8760 hours per year, instead of limiting increased reserve requirements to times and conditions when increased solar generation might cause reserve shortfalls, could also result in excessive cost. Fourth, Mr. Kirby argued that the added reserves to come from online, spinning generation rather than allowing lower cost non-spinning resources to provide some or all of the added reserves, greatly increases the cost of supplying additional reserves. Both of these are methodological errors. In addition, he argued that the study methodology has not undergone independent peer review or a technical review committee that could help further vet the proposed approach and findings.

On October 21, 2019, Duke, SCSBA, SACE/CCL, and Johnson Development ("Settling Parties") filed a Partial Settlement Agreement ("SISC Settlement") with the Commission addressing these parties' agreement as to the reasonable and appropriate quantification of DEC's and DEP's ancillary services costs and respective SISCs to be approved by the Commission. The SISC Settlement was entered into the record as Hearing Exhibit No. 1.

The Settling Parties agreed in the SISC Settlement that Duke's quantification of the near-term projected capacity represented by "Existing plus Transition" solar QFs to be installed on the DEC and DEP systems, 840 MW and 2,950 MW, respectively, is reasonable for use in this proceeding. The Settling Parties also agreed that the integration services charges of $1.10/MWh (DEC) and $2.39/MWh (DEP) are reasonable, for purposes of this proceeding, for small solar power producers that enter into a PPA or establish a Legally Enforceable Obligation prior to the effective date of avoided cost calculations and methodologies filed in the Companies' next avoided cost proceeding. In addition, they agreed that the solar Integration Services Charges should not be subject to adjustment during the term of the PPA, and that the charges should apply prospectively only to projects subject to the avoided cost methodologies and contractual terms and conditions established in this proceeding, and not to the rates established in prior avoided cost proceedings. (Hearing Exhibit No. 1, p. 2-3.)

The SISC Settlement also addressed the application of the SISC to "controlled solar generators" stating that Duke cannot impost the SISC on a solar QF that is operating as a "controlled generator." The Settlement defined "controlled solar generator" as "any solar QF that demonstrates that its facility is capable of operating, and contractually agrees to operate, in a manner that materially reduces or eliminates the need for additional ancillary service requirements incurred by the utility, including but not limited to QFs equipped with battery storage." (Hearing Exhibit No. 1, p. 3-4.)

Recognizing that the Astrapé Study presents novel and complex issues that warrant further considering, the SISC Settlement also requires Duke to submit the study methodology and inputs to an independent technical review and include the results of that review and any revisions in its initial filing in the next avoided cost proceeding. The Settling Parties further agreed that to the maximum extent practicable the independent review of the study methodology shall take into consideration the South Carolina Integration Study called for by S.C. Code Ann. § 58-37-60, and that this process shall be subject to Commission oversight and comment from interested stakeholders. The Settling Parties further agreed that undertaking the work associated with the independent technical review is reasonable and appropriate to effectuate Act 62 compliance. (Hearing Exhibit No. 1, p. 3-4.)

At the hearing, Duke Witnesses Snider, Wheeler, and Wintermantel provided support for, and recommended approval of the SISC Settlement. Similarly, SACE/CCL Witness Kirby and SCSBA Witness Burgess provided support for, and recommended approval of the SISC Settlement. Accordingly, each of these Duke, SACE/CCL, and SCSBA witnesses stated that nothing in their testimonies should be construed as advocating for a position that is contrary to the terms of the SISC Settlement. (Tr. Vol. 1, p. 56, 258, 299, 378, Tr. Vol. 2, p. 458.) ORS also notified the Commission during the hearing that while ORS would not be a signatory to the SISC Settlement, ORS did not object to the SISC Settlement. (Tr. Vol. 1, p. 179.)

Commission Determination

In enacting Act 62, the South Carolina General Assembly directed this Commission to consider ancillary services avoided or incurred by the electrical utility in the methodology used in establishing avoided cost rates. *See* Section 58-41-20(B)(3). Duke's Joint Application presented the Integration Services Charge as responsive to Act 62's directives and as necessary and appropriate to recognize the costs that Duke is now incurring to integrate solar generators into the DEC and DEP Balancing Authorities and to more accurately and appropriately value the energy and capacity provided by solar QFs eligible for Schedule PP. ORS Witness Horii provided similar testimony based upon his experience that utilities in other parts of the country are incurring increased additional ancillary services costs due to the integration of intermittent solar resources. The Commission finds the testimony provided by Duke Witnesses Snider and Wintermantel, as well as the results of the Astrapé Ancillary Services Study and Mr. Horii's testimony, provide persuasive evidence that Duke is incurring increased ancillary services costs to integrate increasing penetrations of intermittent "must-take" solar QFs. Therefore, as an initial matter, the Commission finds and concludes that establishing a solar Integration Services Charge is necessary and appropriate under the directives of Act 62 and in order to accurately quantify the costs being avoided by purchasing power from solar generators being installed on the DEC and DEP systems.

Turning to the quantification and application of an integration services charge, the Commission gives substantial weight to the testimony of SCSBA, SACE/CCL and Duke witnesses regarding the issues addressed in the SISC Settlement, which generally supports

Duke's initial proposal to establish the Integration Services Charge as outlined in Duke's Joint Application. Specifically, the SISC Settlement supports applying a SISC of $1.10/MWh in DEC and $2.39/MWh in DEP as reasonable for solar small power producers that enter into a PPA or establish a Legally Enforceable Obligation prior to the effective date of avoided cost calculations and methodologies filed in the Companies' next avoided cost proceeding. The SISC Settlement further provides that these charges should not be subject to adjustment during the PPA, and that the SISC will only apply on a prospective basis, thereby balancing the interest of solar generator owners and customers. In this regard, the Commission gives substantial weight to ORS's non-objection to the SISC Settlement entered into between the Settling Parties resolving the otherwise-controverted issue of integration costs in these proceedings.

The SISC Settlement also provides that Duke cannot impose the SISC on a solar QF that is a "controlled solar generator," and that Duke must file with the Commission by November 18, 2019, for review and comment, proposed guidelines for QFs to become "controlled solar generators" and thereby avoid the SISC. The Commission finds these provisions reasonable.

In addition, the Commission finds the provision that Duke shall submit the study methodology and inputs to an independent technical review and include the results of that review and any revisions in its initial filing in the next avoided cost proceeding reasonable, and finds that this provision appropriately addresses concerns raised by Mr. Horii regarding updating the integration charges.

The Commission concludes that the SISC Settlement is the product of the "give-and-take" of settlement negotiations between Duke, SCSBA and SACE/CCL in an effort to appropriately balance the Settling Parties' interests in reasonably and accurately quantifying the increased ancillary services costs being incurred by Duke and customers as a result of the growing solar generation being installed on the DEC and DEP systems. The Commission also recognizes Power Advisory's findings that this Settlement presents a reasonable accommodation among the parties regarding the contentious issues surrounding variable resource integration charges. *Power Advisory Report*, at 30. Further, as stated by Duke during the hearing, the terms of the SISC Settlement are also consistent with the NC Utilities Commission's *October 17, 2019 Supplemental Notice of Decision*, and which this Commission has taken judicial notice of such Decision in these proceedings. (Tr. Vol. 1, p. 10-11, 15.) The Commission finds that the SISC Settlement strikes a fair balance between the interests of the Companies, the solar generators that will be subject to the Integration Services Charge and customers. The Commission has fully evaluated the provisions of the SISC Settlement and concludes, in the exercise of its independent judgment that the provisions of the SISC Settlement are just and reasonable to all parties to this proceeding in light of the evidence presented and serve the public interest. The Commission also finds that Duke has adhered to Act 62's directives in establishing the solar Integration Services Charge as described in the SISC Settlement. Based upon the foregoing and entire evidence in this proceeding, the Commission hereby approves the terms of SISC Settlement and application of solar Integration Services Charge to Schedule PP as defined therein.

H. Standard Offer

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 23-25

The evidence in support of these findings of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Act 62 establishes provides that the Commission shall approve a Standard Offer tariff and support terms and conditions to be available to small power producer QFs that are 2 MW or smaller. S.C. Code Ann. § 58-41-20(A), S.C. Code Ann. § 8-41-10(15). Act 62 requires that power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by FERC implementing PURPA. S.C. Code Ann. § 58-41-20(B)(2).

Summary of the Evidence

The Companies propose for Commission approval the Companies' Standard Offer, which includes the Companies' respective Schedule PP (SC) Purchased Power tariffs ("Standard Offer Tariff" or "Schedule PP"), Terms and Conditions for the Purchase of Electric Power ("Standard Offer Terms and Conditions" or "Terms and Conditions"), and Standard Offer power purchase agreement ("Standard Offer PPA") available to all qualifying cogenerators and small power production QFs up to 2 MW in size. These documents memorialize the contractual relationship between the Companies and smaller QFs up to 2 MW selling power to the Companies under the Standard Offer. The Commission most recently approved the Companies' Standard Offer contracting documents in Order No. 2016-349, issued on May 12, 2016.

Standard Offer Tariff

As described by Witness Wheeler, the Standard Offer Tariff sets forth the Companies' avoided cost rates and contract terms available to Standard Offer QFs desiring to sell energy and capacity to DEC and DEP under PURPA. (Tr. Vol. 1, p. 260.7.) The Companies' Standard Offer Tariffs provide eligible QFs with variable, 5-year, and 10-year fixed term options. Witness Wheeler testified that the effective date of the Standard Offer Tariff should be November 30, 2018, because this is the date on which the previously-effective Standard Offer Tariff expired.[21] (Tr. Vol. 1, p. 260.9.) Witness Wheeler explained that establishing the effective date any later date than November 30, 2018, would result in the absence of long-term fixed avoided cost rate credits pursuant to which new Standard Offer QFs could sell power to the Companies pursuant to PURPA as of November 30, 2018. (Tr. Vol. 1, p. 260.9.)

ORS Witness Horii testified that the Standard Offer Tariff complies with the requirements of Act 62 and PURPA. (Tr. Vol. 2, p. 525.26-525.27.) As Witness Wheeler testified at the evidentiary hearing, only a portion of issues originally in contention between the Companies and SBA were unresolved as of the date of the hearing. (Tr. Vol. 1, p. 257-258.) The first provision remaining unresolved is the requirement for a QF to begin delivering power within 30 months from the date of the order approving the Tariff (and which may be extended under limited circumstances set forth in the Tariff). Witness

[21] On November 30, 2018, DEC and DEP jointly filed an application with the Commission in Docket No. 1995-1192-E to update their standard offer avoided cost rates and Standard Offer Tariffs. On April 4, 2019, the Hearing Officer issued an order placing that proceeding in abeyance in recognition of the Legislature's ongoing consideration of what is now Act 62. *See* Standing Hearing Officer Directive 2019-47H. The Companies filed a letter in Docket No. 1995-1192-E withdrawing their November 30, 2018 Application concurrently with filing the Application in the instant proceeding on August 14, 2019.

Wheeler's testimony explained that this provision was added to both the Standard Offer PPA and Standard Offer Tariff in 2016 to require QFs to complete construction and begin delivery of generation in a timely manner. (Tr. Vol. 1, p. 262.10.) Witness Wheeler explained that without this requirement, a QF can enter into a Standard Offer PPA and wait an indefinite period of time before beginning to sell power to the Companies, and that this would hypothetically allow a QF to enter into a Standard Offer PPA in 2019 and begin selling its output to the Companies in 2025, for a period ending in 2035, at rates set in 2019. (Tr. Vol. 1, p. 262.10.) SBA Witness Levitas's direct testimony described his concern that QFs cannot satisfy the requirement to deliver power within 30 months after the rates are approved because of delays in the interconnection process. (Tr. Vol. 1, p. 322.29.) SBA Witness Levitas' surrebuttal testimony subsequently recommended that the in-service date should be linked to Interconnection Facilities and Network Upgrades In-Service Date. (Tr. Vol. 1, p. 324.12.)

Standard Offer PPA: Standard Offer Terms and Conditions

The Standard Offer PPA is the pro forma PPA that the Companies use to contract with QFs eligible for the Standard Offer for the purchase of energy and capacity under PURPA. The Terms and Conditions are incorporated into the Standard Offer PPA by reference (*see* Section 2 of the PPA) and set forth the contractual obligations of both the QF and the Companies as necessary to administer Schedule PP and the Standard Offer PPA in a fair and consistent manner.

ORS Witnesses Horii and Lawyer testified that the Standard Offer PPA and Standard Offer Terms and Conditions, as amended by Witness Wheeler's rebuttal testimony, complies with the requirements of Act 62 and PURPA. (Tr. Vol. 2, p. 528.15, 532.6-7.) As Witness Wheeler testified at the evidentiary hearing, of the issues originally in contention between the Companies and SBA with regard to the Standard Offer PPA and Terms and Conditions, only several issues remained unresolved as of the date of the hearing. (Tr. Vol. 1, p. 257-258.) The Commission has addressed the issue involving the "30-month" provision in the preceding paragraphs, which leaves the issue of "material alteration" as the only issue to be addressed herein.

SBA Witness Levitas agreed to Duke's provisions in the Standard Offer PPA and Standard Offer Terms and Conditions that address when a QF Seller can make modifications to a Standard Offer QF project selling power to the Companies, but believes that those revisions to the Standard Offer PPA and Standard Offer Terms and Conditions should only be applied on a going-forward basis. Witness Wheeler addressed this at the hearing, explaining that such an interpretation would contradict longstanding existing language in the rate update section of Schedule PP in Provision 1(b) of the Terms and Conditions. (Tr. Vol. 1, p. 267.)

Commission Determination

Standard Offer Tariff

As explained below, the Commission adopts the Standard Offer Tariff proposed by the Companies in Witness Wheeler Direct DEC Exhibit 2 and Witness Wheeler Direct DEP Exhibit 2, with the revised Storage Protocols, as agreed to by SBA and the Companies.[22] The Commission finds that the Standard Offer Tariff is commercially reasonable and

[22] The Revised Storage Protocols are set forth in Duke Witness Wheeler's Rebuttal Exhibit 5.

consistent with regulations and orders promulgated by FERC implementing PURPA, as required by Act 62. The Commission agrees with Duke Witness Wheeler that removing the "30-month" provision would be unjust and unreasonable to customers and in contradiction to PURPA, FERC's implementing regulations, and Act 62, which require the utility's avoided cost to be an accurate reflection of the utility's actual incremental costs of alternative energy. (Tr. Vol. 1, p. 262.10.) The Commission acknowledges Power Advisory's opinion that QFs should be provided extensions on their in-service date for any delays associated with interconnection facilities and network upgrades, but believe this concern is outweighed by the need to ensure avoided cost rates are accurately calculated. *Power Advisory Report*, p. 45. Also, requiring commercial operation within 30 months from the date of the Commission's order is a reasonable timeframe to resolve interconnection issues given the smaller generation capacities applicable under a Standard Offer PPA. Moreover, the Commission believes the language of the Tariff provides sufficient flexibility to QFs that are close to achieving commercial operation within the required timeframe. Specifically, the 30 month time frame "may be extended beyond 30 months if construction is nearly complete and Seller demonstrates that it is making a good faith effort to complete its project in a timely manner." The Commission agrees with Witness Wheeler that retaining this provision in the Standard Offer PPA and Standard Offer Tariff is imperative to ensuring QFs cannot sell power under stale and inaccurate avoided cost rates, for which customers are financially responsible. (Tr. Vol. 1, p. 262.11.) To adopt Witness Levitas's recommendation from his surrebuttal testimony would provide an extensively open-ended period through which QFs may be eligible for avoided cost rates that have become stale. The Commission's determination in this regard applies to the Standard Offer PPA, as well.

Additionally, the Commission agrees with Witness Wheeler that the effective date of the Standard Offer Tariff is November 30, 2018. No Party offers any testimony to the contrary in this regard. Pursuant to the terms of the previously-effective Standard Offer Tariff, as approved by this Commission, such tariff expired on November 30, 2018, when new avoided cost rates were proposed by the Companies. The Commission concludes that the Standard Offer Tariff under consideration in this proceeding should be effective as of November 30, 2018, and that the avoided cost rates approved in this proceeding should apply to those QF Sellers that committed to sell power to the Companies as of November 30, 2018.

<u>Standard Offer PPA: Standard Offer Terms and Conditions</u>

The Commission finds the Standard Offer PPA and Standard Offer Terms and Conditions, as described in Witness Wheeler's rebuttal testimony, are commercially reasonable and consistent with regulations and orders promulgated by FERC implementing PURPA, as required by Act 62. The Commission agrees with Witness Wheeler that changes to the Standard Offer Tariff and Terms and Conditions, with the exception of changes to the levelized rates, have historically applied retroactively to QFs with existing PPAs. As Witness Wheeler testified, the application of the Standard Offer Tariff and Terms and Conditions are no different than any other retail tariff, the changes for which apply to new and existing customers (or QFs in this instance) upon approval by the Commission. (Tr. Vol. 1, p. 260.17.) While the Commission acknowledges Power

Advisory's opinion that changing contract terms retroactively can be problematic in ensuring lender and developer certainty, providing additional clarification to existing contract provisions that may be unclear given changed conditions from the time that the pre-existing tariff was developed also creates improves certainty for QF developers. Moreover, any such changes require Commission approval to determine the reasonableness and appropriateness of the proposed changes. As Witness Wheeler pointed out, Section 2 of the Standard Offer PPA affirmatively puts existing QF Sellers on notice of potential future changes. (Tr. Vol. 1, p. 260.17.) Absent the requested clarification, Paragraph 1(i) in the current Terms and Conditions already allows the Companies to terminate the agreement due to the QF's inability to deliver the contracted capacity and energy agreed to in the PPA.

I. Large QF PPA

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 26-29

The evidence in support of these findings of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Summary of the Evidence

The Large QF PPA is the standard form PPA that the Companies propose to use to contract with small power producer QFs greater than 2 MW in size and not eligible for the Standard Offer ("Large QF") that commit to sell and deliver energy and capacity to the Companies. The Commission's authority to review and approve the terms and conditions of contracts between QFs and electric utilities is not new, *see* S.C. Code Ann. § 58-3-140 and 26 S.C. Code Ann. Regs. 103-303); however, Act 62 now expressly requires the Commission to review and approve one or more standard form PPAs for use by small power production facilities not eligible for the Standard Offer. S.C. Code Ann. § 58-41-20(A). The Act provides that such form PPAs should not be determinative of the avoided cost price and length (or "term") of the power purchase agreement, but requires utilities' form PPAs to contain certain commercial terms and conditions, including, but not limited to, provisions addressing force majeure, indemnification, choice of venue, and confidentiality. S.C. Code Ann. § 58-41-20(A). Consistent with PURPA, Act 62 also provides utilities and QFs the freedom to enter into PPAs with terms that differ from the Commission-approved form PPA. S.C. Code Ann. § 58-41-20(A) (such PPAs must be filed with the Commission pursuant to S.C. Code Ann. § 58-41-20(D)). Act 62 also generally requires that all PPAs be commercially reasonable and consistent with regulations and orders promulgated by FERC implementing PURPA. S.C. Code Ann. § 58-41-20(B)(2).

Duke Witness Johnson testified that the proposed Large QF PPA is a comprehensive power purchase agreement providing for the exclusive purchase and sale of 100% of the output of energy and capacity from a QF facility on a fixed price, fixed term basis. Further, he stated, the PPA is substantially similar to the form of PPA that the Companies have used to contract with large QF facilities (including numerous large solar QF facilities) over the past several years. (Tr. Vol. 1, p. 282.24.)

ORS Witnesses Horii testified that the Companies' Large QF PPA is commercially reasonable and conforms to applicable PURPA and FERC guidelines. (Tr. Vol. 2, p. 525.26.) SBA Witness Levitas identified several areas of concern with the Large QF PPA in his direct testimony; however, Duke witness Johnson testified at the evidentiary hearing that only a few of the issues originally in contention between the Companies and SBA were unresolved as of the date of the hearing. (Tr. Vol. 1, p. 275.)

Methodology for Calculating Liquidated Damages

With regard to the methodology for calculating liquidated damages, at the evidentiary hearing, SBA Witness Levitas testified that SBA was agreeable to accepting the calculation of liquidated damages as proposed in Duke Witness Johnson's rebuttal testimony (Tr. Vol. 1, p. 309-310), which represents a capacity-based calculation of liquidated damages. (Tr. Vol. 1, p. 284.9.) Under this methodology, liquidated damages within the Large QF PPA would be calculated as follows:

> For Facilities with Nameplate Capacity Rating up to 15 MW: the default Liquidated Damages shall be equal to the average annual estimated capacity payment under this Agreement over the Term; for PPAs with Nameplate Capacity > 15 MW the default Liquidated Damages shall be equal to: for the first 15 MW (the average annual estimated capacity payments under this Agreement over the Term) + $10,000 per MW for any nameplate capacity above 15 MW. (Tr. Vol. 1, p. 284.9)

Alternate Eligibility Criteria for QF Sellers to Enter into PPA

Additionally, an outstanding issue existed as of the date of the hearing with regard to the criteria that QF Sellers must satisfy before entering into the Large QF PPA. In Duke Witness Johnson's rebuttal testimony, in response to certain suggestions by Duke Witness Levitas, the Companies revised the eligibility for the Large QF PPA to require that a QF Seller must have executed and returned a Facilities Study Agreement to the Companies pursuant to the South Carolina Generator Interconnection Procedures ("SCGIP"). (Tr. Vol. 1, p. 284.11.) Witness Levitas' testimony advocated for the Companies to adopt an alternate eligibility criteria for QF Sellers in the event that a QF has not received a Facilities Study Agreement within one year of becoming an Interconnection Customer. (Tr. Vol. 1, p. 322.28.) Witness Levitas testified that such protection for QF Sellers is necessary given the Companies' lengthy interconnection process. (Tr. Vol. 1, p. 322.28.) In response, Witness Johnson testified that QF Sellers should not be allowed to enter into a PPA prior to receiving a System Impact Study Report. He explained that the QF would not have any insights into the cost of its required interconnection facilities and system upgrades, and, therefore, would not be to the point in the development process of knowing whether the generating facility is commercially viable or not. (Tr. Vol. 1, p. 284.30.)

Termination of PPA for Interconnection Costs

Witness Levitas proposed in his surrebuttal testimony that QFs should be able to terminate a PPA without incurring liquidated damages if the costs of interconnection exceed $75,000 per megawatt. In support of his proposal, Witness Levitas stated that many binding contractual relationships include conditions precedent that allow a party to terminate the contract under limited circumstances. He further stated that his recommended provision is necessary where the utility fails to complete the System Impact Study in a timely fashion, and the QF is allowed to form a LEO or enter into a PPA. In response, Witness Johnson contended that incorporating this provision would be meaningless because the QF Seller will already know its interconnection costs at the time that it enters into a PPA. (Tr. Vol. 1, p. 284.17.)

Surety Bond as Performance Assurance

The final remaining item with regard to the Large QF PPA is Witness Levitas' proposal that Duke allow the use of surety bonds as a form of performance assurance. (Tr. Vol. 1, p. 324.5.) Duke Witness Johnson addressed this issue at the hearing, testifying that Duke has never allowed a surety bond in any previous PPA and that Duke already considered this issue when developing the PPA for CPRE. He further testified that Duke does not believe it would be a permissible form of performance assurance because a surety bond, when compared to other forms of security, is more difficult to collect on. (Tr. Vol. 1, p. 280.) Duke Witness Wheeler also testified at the hearing that Duke decided to move away from allowing surety bonds several years ago because the Companies found that in some cases, the QF did not renew the surety bond for the life of the contract. (Tr. Vol. 1, p. 289-290.)

Commission Determination

First, we adopt the agreed-upon calculation of liquidated damages using the capacity-based calculation, as set forth in Duke Witness Johnson's rebuttal testimony. The Commission finds merit in Duke Witness Johnson's testimony and agrees with Duke that it represents a commercially reasonable methodology for calculating liquidated damages. Additionally, we believe it is reasonable to require QFs to have returned a signed Facilities Study Agreement to the Companies prior to entering into a PPA. Based on the testimony in the record, this point in the development process provides QFs with sufficient information about the viability of their project to know whether the QF can legitimately make a commitment to develop the project and sell the output to the utility.

We recognize Power Advisory's opinion that conditioning a PPA on a signed and returned Facilities Study Agreement could allow Duke to delay delivering the System Impact Study, and therefore control or frustrate PPA execution. The Commission also recognizes FERC's precedent from 2016, which held that requiring an executed Interconnection Agreement as part of a State's LEO standard is inconsistent with FERC's PURPA regulations because it allows the utility to "control whether and when a legally enforceable obligation exists." *FLS Energy, Inc.,* 157 FERC ¶ 61,211 at P. 23 (2016). However, the record establishes that the interconnection process takes several years to complete, and that such perceived "delay" in the interconnection process is often a result of the volume of Interconnection Requests in the queue requesting to interconnect in the same areas. (Tr. Vol. 1, p. 282.34-35.) No party disputes this characterization of the interconnection delays by Duke Witness Johnson. The Commission agrees it would be improper for the utility to intentionally withhold a System Impact Study or Facilities Study Agreement in order to frustrate or control PPA execution. However, the Commission is concerned that permitting QF Sellers to enter into PPAs one year after the Interconnection Request is submitted would result in QFs selling power to the utility under stale rates, given the interconnection timeframes and flexible commercial operations date, which was agreed to by the Companies at Witness Levitas' request. In weighing these considerations, we believe that providing the flexible commercial operations date that is proposed in Duke Witness Johnson's rebuttal testimony provides QFs significant flexibility, which should be balanced by limiting the eligibility criteria for entering into a PPA until the QF signs and returns a Facilities Study Agreement to the utility. Given this Commission's ability to adjudicate complaints between QFs and utilities under the Commission's jurisdiction, QF Sellers has a reasonable and appropriate remedy in the event that a QF believes that the utility is withholding a System Impact Study or Facilities Study Agreement intentionally to control or frustrate PPA execution.

Given our determination on the eligibility criteria for entering into the Large QF PPA, the Commission concludes that no value exists in adding a provision that allows the QF to terminate the PPA if its interconnection costs exceed $75,000 because the QF Seller will have an estimate of its interconnection costs prior to entering into a PPA. Moreover, we believe that such a provision would be counter to the notion of making an unequivocal commitment to sell power, as is contemplated by entering into a legally enforceable obligation, whether contractual or non-contractual. The Commission also finds that this proposal cannot be reconciled with Mr. Levitas' own Direct Testimony that "a QF must make a binding commitment to sell its output" to establish a LEO and that a QF should not be allowed to obligate the utility to purchase its power but then be allowed to "walk away with no consequences." (Tr. Vol. 322.22.)

Finally, with regard to the appropriate forms of performance assurance, consistent with Power Advisory's opinion, we believe that Duke's three forms of performance assurance offered – cash, letter of credit, and a guarantee – are commercially reasonable, and that the utility should retain some level of discretion in determining the appropriate form of performance assurance. We understand that various utilities approach these discrete issues differently, but are not persuaded that Dominion's adoption of the surety bond proposal is evidence that it is an appropriate form of performance assurance for Duke.

J. Notice of Commitment Form

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 30-33

The evidence in support of these findings of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Section 58-41-20(D) of the Act provides that small power producer QFs (as defined in the Act) shall have the right to sell their electric output to an electric utility by executing and delivering to the utility a Commission-approved "notice of commitment to sell form." By delivering a Notice of Commitment Form ("Form"), the Act prescribes that the small power producer is committing to sell its output (a) at the avoided cost rates, and (b) pursuant to the PPA terms in effect at the time it submits the Form to the utility. The Act does not specify each element of the Form required to establish the QF's "commitment to sell," but makes clear that the Form must provide the small power producer a "reasonable period of time" from submittal of the Form to execute a PPA with the utility. The Act also prohibits a utility from requiring a small power producer to execute a PPA prior to receiving "a final interconnection agreement from the electrical utility" as a condition to "preserving the pricing and terms and conditions established by its submittal of the form to execute a [PPA]." S.C. Code Ann. § 58-41-20(D).

Underlying Act 62's directive to establish a "notice of commitment to sell" form is the concept of a "legally enforceable obligation," which has been established by FERC's regulations implementing PURPA. FERC's regulations specify that a QF can choose to sell its output to the utility on an uncommitted and "as available" basis or the QF can choose to sell its output pursuant to a "legally enforceable obligation," ("LEO") whereby the QF commits to deliver energy and capacity to the utility over a specified term. *See* 18 C.F.R. § 292.304(d). Where the QF chooses to sell its power pursuant to a LEO, PURPA requires that rates paid to the QF be fixed at the utility's avoided costs calculated at the time the LEO is established or, at the QF's option, at the time the power is delivered. *Id.* FERC has recognized that a LEO may be established by the QF and the utility executing a mutually-binding contract, such as a PPA. However, when a utility refuses to sign a contract, the QF may petition this Commission to recognize the creation of a non-contractual LEO. The parties to this proceeding agree that the South Carolina legislature intended this Notice of Commitment Form to serve as the "non-contractual LEO" that FERC's regulations describe, while the PPAs themselves serve as the "contractual LEO." The parties also agree that the Notice of Commitment Form is a novel concept and that only North Carolina has established such a mechanism to create a non-contractual LEO.

The purpose of the non-contractual LEO, as FERC set forth in Order No. 69, is "to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility." *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 (1980) ("Order No. 69"). As FERC confirmed in its recent Notice of Proposed Rulemaking, FERC's PURPA regulations do not specify when or how a LEO is established, and FERC has not identified specific criteria that states must follow in determining when a LEO is established. PURPA NOPR, at ¶ 134. However, FERC's orders have provided general guidance that "a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, *but binding, legally enforceable obligations*." *JD Wind 1, LLC*, 129 FERC ¶ 61,148 at P25 (2009) (emphasis added). FERC has also recently made clear that "the establishment of a legally enforceable obligation turns on the QF's commitment, and *not* the utility's actions." *FLS Energy, Inc.*, 157 FERC ¶ 61,211 at P 24 (Dec. 15, 2016) (emphasis in original).

Summary of the Evidence

As described by Duke Witness Johnson, the Companies' Notice of Commitment Form has been developed to identify the QF "Seller" making the commitment to sell and to then require the QF to certify that it is actually making a commitment substantial enough to establish a binding LEO. (Tr. Vol. 1, p. 282.14.)

ORS Witness Horii found the Companies' Notice of Commitment Form to be consistent with PURPA and FERC's implementing regulations. (Tr. Vol. 2, p. 525.25.) SBA Witness Levitas identifies several areas of concern with the Notice of Commitment Form in his direct testimony, the majority of which have been successfully addressed by Duke Witness Johnson's rebuttal testimony and exhibits. Witness Johnson testified at the evidentiary hearing that only a few of the issues originally in contention between the Companies and SBA were unresolved as of the date of the hearing. (Tr. Vol. 1, p. 275.)

The first remaining issue in contention is whether the Companies may condition eligibility for the Notice of Commitment Form on the requirement that a QF must have secured all required permits and land use approvals. SBA Witness Levitas and Duke

Witness Johnson offer competing testimony on whether this is a reasonable requirement. Witness Johnson further argued that it establishes a reasonable showing of commercial viability and financial commitment to construct the QF facility, (Tr. Vol. 1, p. 284.33) and Witness Levitas testified that achieving the required permits and approvals is expensive, and that the QF should be permitted to secure financing before it must pay for such permits and approvals. (Tr. Vol. 1, p. 322.25.) Witness Johnson also pointed to other states (namely, Montana and Minnesota) which have approved similar requirements for establishing a LEO. (Tr. Vol. 1, p. 284.34.)

The second remaining issue in contention is whether the Companies may require the QF to achieve commercial operation within 365 days of executing the Notice of Commitment Form. Witness Levitas testified that this deadline should be extended to account for additional time required for the utility to complete required Interconnection Facilities and Network Upgrades. (Tr. Vol. 1, p. 324.8.) Witness Levitas argued that given the delays that can occur in the interconnection process, almost no QF can be certain that it can achieve commercial operation within 365 days. (Tr. Vol. 1, p. 324.8.) In response, Duke Witness Johnson argued that uncertainty is an inherent risk that QF developers assume when undertaking a new investment. (Tr. Vol. 1, p. 284.25.) Witness Johnson further explained that a QF is not required to execute a Notice of Commitment Form in order to secure pricing, and that a QF may opt to enter into a PPA if it does not want to take on the risk associated with a requirement to deliver power within 365 days. (Tr. Vol. 1, p. 284.25-26.) Witness Johnson also pointed to other states (namely, Texas, New

Mexico, and Idaho) which have approved similar or more conservative requirements for establishing a LEO. (Tr. Vol. 1, p. 282.17, 284.27-28.)

Commission Determination

The Commission agrees with Duke that requiring a QF to have secured all required permits and land use approvals is a reasonable criterion to apply in assessing whether the QF has made an unequivocal commitment to sell power to the utility pursuant to the Notice of Commitment Form. Securing all permits and approvals required to construct a solar facility is a threshold requirement in initiating the development process and bringing a project toward viability to sell power to the utility. Accordingly, the Commission finds that requiring the QF to have obtained such approvals is consistent with establishing a substantial and binding commitment to sell. We acknowledge Power Advisory's recommendation to remove this requirement to balance the "give and take" between SBA and the Companies, and that the requirement for QFs will likely motivate QFs to move forward with viable projects only. *Power Advisory Report*, at 53. However, we find that the proposed requirement is not inconsistent with the intent of the non-contractual LEO concept as originally set forth by FERC, and is reasonable to ensure only projects actually able to commit to sell their power to the utility are securing rates to be paid by customers for many years to come.

The Commission also finds persuasive the testimony indicating that the Notice of Commitment Form will be used only in very unique circumstances by QFs. As testified to by Duke Witness Johnson, nothing requires a QF to enter into a Notice of Commitment Form in order to secure pricing and sell output to the utility. (Tr. Vol. 1, p. 284.25-26.)

Further, SBA Witness Levitas testified that entering into a LEO is best established by executing a PPA, and that where form contract and applicable pricing have been approved by a state commission, PPA execution "is an easy matter." (Tr. Vol. 1, p. 324.6.) Witness Levitas goes on to testify that the Notice of Commitment Form is "only needed where there is some reason that a QF cannot tender a signed PPA to the utility." (*Id.*) FERC's guidance that a non-contractual LEO is available to QFs in the unique instance that a utility is "refusing to enter into a [PPA]" supports this conclusion as well, given the establishment of the form Large QF PPA through Act 62. Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,880. In sum, we conclude that the requirement to obtain all land-use approvals and required permits is appropriate for the Notice of Commitment Form, and that to the extent such a requirement is uniquely burdensome for a particular QF, it may choose to enter into the Large QF PPA, as established by the Commission in this proceeding.

Additionally, the Commission agrees that requiring a QF to achieve commercial operation within 365 days of executing the Notice of Commitment Form is reasonable and that this time period should not be extended for the construction of Network Upgrades or Interconnection Facilities, as proposed by Witness Levitas. As an initial matter, the Companies believe that the 365-day requirement is not inconsistent with FERC's regulations or orders implementing PURPA, and while the Commission recognizes that some states have adopted more lenient criteria, certainly other states have adopted more stringent standards than 365 days. From a practical perspective, the Commission notes that the record indicates that a need for an extension in the 365 days will rarely occur. Given the requirement that a QF must execute the PPA within 90 days after the PPA is tendered to the QF by the utility (unless extended by mutual agreement of the parties), the Commission finds that it is highly unlikely that any QF will not execute a PPA prior to the 365-day commercial operation deadline. At such time of PPA execution, the Notice of Commitment Form automatically terminates, and the flexible COD provisions of the Large QF PPA apply. Given Act 62's requirement that the utilities offer a form PPA approved by the Commission, such instance will not arise, absent intentional disregard of this Commission's order, which the Commission does not expect.

Finally, the Commission notes that the issues described in our discussion of the Large QF PPA *infra* regarding the option for QFs to terminate the Large QF PPA if the interconnection costs exceed $75,000 per megawatt apply to the Notice of Commitment Form as well; therefore, our conclusion is also applicable to the Notice of Commitment Form.

K. Consideration of Longer Term Fixed Price PPA Proposal

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NO. 34

The evidence in support of this finding of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

As recognized earlier in this Order, the General Assembly has mandated that Duke must initially offer to purchase power from small power producer QFs pursuant to fixed price PURPA PPAs with commercially reasonable terms and a duration of ten years. Duke has met this requirement by submitting DEC's and DEP's Standard Offer Schedule PPs for QFs up to 2 MW and the Large QF form of PPA for small power producers 2 MW to 80

MW that are not eligible for the Standard Offer. Act 62 also provides that the Commission "may . . . approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, which must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including but not limited to, a reduction in the contract price relative to the ten year avoided cost." *See* S.C. Code. Ann. § 58-41-20(F)(1).

Summary of the Evidence

Recognizing that the obligation to offer fixed price PPAs for durations longer than 10 years is an option provided to intervenors under Act 62, Duke's Joint Application and direct testimony did not present such a proposal. However, Duke did address the overpayment risk of longer-term fixed price contracts. Duke Witness Brown testified that primary components that contribute to the over-payment risk for customers under PURPA are: (1) avoided cost rates, (2) length of contract, and (3) the volume of contracts. He explained that the Companies' recent experience has been that paying above-market avoided cost prices over a long period of time for an infinite number of QF contracts resulted in the current $2.26 billion overpayment obligation based upon DEC's and DEP's existing PURPA obligations. Because the Commission cannot control the volume of contracts the Companies must enter into under PURPA and because Act 62 mandates that the Companies must offer long-term ten-year contracts for significant QF capacity until the 20 percent thresholds set in Act 62 are reached, Mr. Brown testified that it is imperative that the Commission ensure avoided cost rates are accurately calculated. (Tr. Vol. 1, p. 46.16.) The Commission has more fully addressed Duke's testimony on this issue as well as the Commission's determination that such risks are an important consideration in reducing the risk on the using and consuming public earlier in this Order and will not summarize that testimony and the Commission's findings again here.

Johnson Development Witness Chilton testified to her perspective on the financing needs of QFs and the contract terms that Johnson Development recommends should be offered to small power producer QFs. Ms. Chilton contended that PURPA and Act 62's requirements that QF generation must be allowed to compete on even terms with the utility's other generation resources, both present and projected, implicitly requires that the QF be able to obtain regularly-available, market-rate financing for the costs of developing, building, and operating their projects. (Tr. Vol. 1, p. 334.4). She explained that based upon her experience only a limited number of QFs have been able to find financing for short term or low price PPAs. (Tr. Vol. 1, p. 334.4-5.) She further contended that the longer the contract term, accompanied by a reasonable avoided cost-based purchase price, the more mainstream capital will be available for QF development. Ms. Chilton argued that while PURPA and FERC regulations defer to state Commissions to direct PPA terms, Act 62 recommends ten-year term as a starting point, but does not limit PPAs to ten years. (Tr. Vol. 1, p. 334.4-5.) To support Commission consideration of longer contract terms, Johnson Development Witness Chilton points to Duke's recent participation in the North Carolina CPRE Program where Ms. Chilton argues Duke "seized 45% of the all PPAs awarded" and pointed to the Companies' unregulated affiliate, Duke Energy Renewables, recent participation in Georgia competitive solicitation. The contract term offered under the North Carolina CPRE Program is 20 years, while the contract term for the Georgia

Power competitive solicitation is 35 years. Ms. Chilton also recognized that Act 62 requires the Commission to consider decrements to avoided cost for PPA terms of longer duration, and recommended the Commission set the tenor of length of PPA contracts at a minimum of 15 and in some cases 20 years with "appropriate statutory conditions" as required by in S.C. Code Ann. § 58-41-23 20(F)(1), to facilitate the opportunity to obtain financing for a majority of QFs in South Carolina. (Tr. Vol. 1, p. 334.8, 9-10.)

Witness Chilton further commented on Duke's avoided cost practices since 2017 of offering five year PPA terms to large QFs above the 2 MW standard offer eligibility threshold. She testified that Duke does not provide any indication that they intend to offer PPAs of longer duration, and further suggested that Duke's low proposed avoided cost rates further justify the need for longer PPA tenor to make QFs financeable. (Tr. Vol. 1, p. 334.10.)

In rebuttal, Duke Witness Brown responds to Johnson Development Witness Chilton's testimony regarding ensuring QFs have access to regularly-available, market-rate financing and her advocacy for fixed price PPA terms of 15 years or longer. Witness Brown first explains that neither FERC's regulations, FERC Orders implementing PURPA nor Act 62 prescribes that avoided cost rates and terms offered to QFs must enable their project sponsors to obtain "regularly available market rate financing." (Tr. Vol. 2, p. 621.35.) Witness Brown also comments that Ms. Chilton fails to recognize that there are differences in the financing that would be "regularly available" for sophisticated versus unsophisticated QF developers, for smaller QFs versus larger QFs, or for solar QFs versus other types of QF technologies, and that numerous factors including a QF developer's balance sheet, management team experience and creditworthiness, as well as available tax incentives, and project- and avoided cost-specific considerations including price, contract tenor, the cost of capital, and the risk of the investment, amongst others, all come into play in determining whether an investment can attract debt and/or equity capital. (Tr. Vol. 2, p. 621.35-36.)

Witness Brown also explained that the limited guidance from FERC addressing the issue of QF financeability arose in the context of Connecticut's implementation of PURPA, where the Connecticut Commission had approved the utility offering QFs only a real time energy rate, which FERC found was not consistent with a QF's right to commit to deliver power pursuant to a legally enforceable obligation based upon a forecasted avoided cost rate. Brown explained that in 2016, FERC stated that the term of a legally enforceable obligation should be "long enough to allow QFs reasonable opportunities to attract capital from potential investors," while also clearly reiterating that FERC's regulations do not specify any particular number of years for such legally enforceable obligations, meaning that the term and structure of forecasted avoided cost rates is left to the discretion of the implementing State Commission. (Tr. Vol. 2, p. 621.36 *citing Windham Solar, LLC*, 157 FERC ¶ 61,134 at ¶ 8 (2016).) He also noted that Duke has recently signed nine PPAs totaling 472 MW in North Carolina at that State's maximum five (5) year contract terms. This clearly indicates that developers do not need longer than 10-year contracts to be able to finance projects. (Tr. Vol. 2, p. 621.25.) Witness Brown also explained the FERC PURPA NOPR's findings that longer term fixed price contracts are no longer required to enable QF financing, as FERC is proposing to enable contract structures where the energy component of the rate is updated during the contract term based on market prices at the time energy is delivered. (Tr. Vol. 2, p. 621.36.) Witness Brown also highlighted FERC's findings in the recent PURPA NOPR that assessing the financing needs of the QF industry would also be challenge as technology costs continue to decline. The FERC specifically pointed to Energy Information Administration data showing that the overnight capital cost to construct fixed tilt solar photovoltaic generation declined 67 percent between 2013 and 2017. (Tr. Vol. 2, p. 621.34.) In summary, Witness Brown reiterated that there is no basis to conclude that PURPA requires all QFs to be able to obtain regularly available market rate financing, as suggested by Ms. Chilton, nor is the Commission required to undertake efforts to determine what avoided cost rates, terms and conditions would be "financeable" for QFs.

Witness Brown then explained that if the Commission were to attempt to set avoided cost rates based upon what creates an easily financed rate for developers, this would very clearly violate PURPA and Act 62. (Tr. Vol. 2, p. 621.37.) He also pointed out that the Commission cannot truly know what is required for QFs to obtain financing—or the level of profit sought by QF developers—because PURPA largely exempts QFs from Commission oversight of their profits and business operations so that neither the Companies, the ORS, nor the Commission has any clear insight into a QF developer's business or the level of profit deemed "reasonable" to attract equity capital. (Tr. Vol. 2, p. 621.38.) He also noted recent findings by the North Carolina Utilities Commission that a QF has no limit on, and the Commission has no right to review, the amount of debt QFs may use for financing, the return on equity, or the overall rate of return achieved by QF investors. (Tr. Vol. 2, p. 621.38 *citing Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* at 35, N.C.U.C. Docket No. E-100, Sub 148 (Oct. 11, 2017).) Accordingly, Witness Brown argued that the Commission should reject JDA Witness Chilton's recommendation that the Commission investigate the avoided cost rates and terms that would allow QFs to obtain regularly available market rate financing. (*Id.)*

In response to Witness Chilton's testimony recommending the Commission require the Companies to adopt avoided cost rates for fixed terms of 15 years or longer under PURPA, Duke Witness Brown explained that Duke does not support offering longer term fixed price PPAs in excess of 10 years unless the price is determined pursuant to a competitive procurement framework. He explained the North Carolina CPRE Program and Georgia Power Company's Renewable Energy Development Initiative—each of which have recently competitively solicited 20-year and 35-year fixed price PPAs, respectively—cited by Witness Chilton actually validate Duke's position that there is a less risky and more cost-effective way to procure new solar capacity for customers. These independently-administered competitive solicitation processes approved in North Carolina and Georgia ensure that only the most cost-effective projects are selected, thereby reducing the risk of overpayment and providing ratepayer protection. (Tr. Vol. 2, p. 621.24.) Brown testified that the fact that the Companies' projects won proposals in these independently administered competitive solicitations simply means that Duke's project proposals, along with other winning third-party proposals, delivered the most value for customers at the lowest cost. (Tr. Vol. 2, p. 621.24-25.)

Witness Brown also testified that offering administratively determined fixed price contracts any longer than necessary to comply with Act 62 significantly increases the overpayment risk for customers and, therefore, would be inconsistent with Act 62's directives that the Commission's PURPA implementation decisions should reduce the risk on the using and consuming public who are obligated to pay for QF purchases. Moreover, Witness Brown argued that Johnson Development Witness Chilton does not propose any "appropriate statutory conditions," that would result in longer-term fixed price contracts mitigating the overpayment risk to customers. (Tr. Vol. 2, p. 621.23.)

In addition to offering the 10-year fixed price PPA option required to comply with Act 62, Witness Brown pointed out that South Carolina projects can also compete in the CPRE Program and that both Southern Current and Johnson Development-affiliated solar projects had already successfully participated in Tranche 1 of the CPRE Program. (Tr. Vol. 2, p. 621.20-21.) Witness Brown also highlighted that the 10-year fixed price contracts required to comply with Act 62 will be the longest fixed-price PURPA PPA rates offered in the Southeast for projects larger than one MW. He also noted that Duke has recently signed nine PPAs totaling 472 MW in North Carolina at that State's maximum five year contract terms. (Tr. Vol. 2, p. 621.25.)

In surrebuttal, Johnson Development Witness Chilton reiterated her prior testimony that PPA terms longer than 10 years, while not mandated by Act 62, are expressly encouraged by the Act as a means of promoting renewable energy development in South Carolina. She also argued the Commission should not take into consideration other Southeastern states' less favorable PURPA regimes because they have had less robust

PURPA outcomes. (Tr. Vol. 1, p. 336.4.) Finally, Witness Chilton responded to Duke Witness Brown's testimony that Johnson Development had failed to put forward a PPA with decrement to the 10-year avoided costs as required by Act 62, testifying that she was leaving open the possibility to offer additional testimony as necessary and purporting to "expressly preserve" Johnson Development's right in this docket, future proceedings, and in PPA negotiations to propose various methods of complying with the Act 62 requirements for longer term contracts. (Tr. Vol. 1, p. 336.5.)

During the hearing, Johnson Development Witness Chilton agreed that a decrement to the 10-year avoided cost rate is required in order for the Commission to adopt a fixed price contract for a term longer than 10 years. (Tr. Vol. 1, p. 344.) However, in response to questions from Commissioner Belser, she was unable to identify any specific proposal that Johnson Development supported to comply with the statutory requirements for the Commission to consider a longer-term fixed price PPA. (Tr. Vol. 2, p. 355.) She also identified that the Commission would not be able to eliminate all risk of uncertainty up or down for the ratepayer in considering proposals for longer-term fixed-price contracts. (Tr. Vol. 2, p. 361.) Witness Chilton also explained that "financing party is looking at a number of different factors and at each factor is looking for certainty: certainty in the price, certainty in the length, and certainty in the other types of terms that are involved in the contract. And so the greater the certainty, the more accessibility of the financing." However, she also noted that interest rates don't necessarily improve for longer contracts, admitting under cross examination that it is the investor or "equity holder" that primarily benefits from the longer term of the contract, not necessarily the issuer of debt. (Tr. Vol. 1, p. 344, 348.)

During the hearing, SCSBA Witness Levitas identified conceptual proposals that he believed could mitigate the risk to ratepayers of longer term contracts. He commented that the PPA pricing could be adjusted after the initial 10-year contract term subject to a floor and a ceiling, similar to a hedge arrangement, which would limit future increases or decreases in the PPA price paid to the QF; however, Mr. Levitas could not point specifically to whether such a contract structure had been adopted in another state or whether it was compliant with Act 62. (Tr. Vol. 2, p. 358-359.) He also commented that a longer-term PPA could be structured based upon PPA pricing below the full projected avoided cost over the contract term, pointing out that the Michigan Consumers Energy 10-year term PPA is calculated based upon a five-year escalating avoided cost projection that is then fixed for years 6 through 10. He explained this proposal would reduce the risk for customers by compressing the pricing over a shorter-term period and reduce the risk for the QF by fixing the rate over the term so it is not fluctuating during the term of the contract. (Tr. Vol. 2, p. 359-360.)

During the hearing, in response to questions from Vice Chairman Williams regarding potential "doomsday scenarios" of overpayment risk for ratepayers, Duke Witness Snider pointed out the recent declining cost of solar technology over time would not benefit customers if higher avoided cost rates are fixed for longer terms contracts. (Tr. Vol. 1, p. 201-202.) He explained that the further you go out into the future, the greater the risk, meaning that longer contract tenors exacerbates the overpayment risk for customers. (Tr. Vol. 1, p. 205-206.) Witness Snider therefore advocated that the question for the Commission was how to ensure that the State is procuring the right volume of solar energy at the right pace at the right price, and suggested that a competitive procurement with set volumetric targets helps to mitigate the risk for customers as compared to no volumetric limits and an administratively determined price under PURPA. (Tr. Vol. 1, p. 206.) Duke Witness Brown also responded that if the State is interested in procuring solar energy, then it should be procured at the lowest possible cost of solar energy. (Tr. Vol. 1, p. 203-204.)

Commission Determination

As addressed earlier in this Order, Act 62 requires Duke to offer to enter into 10-year fixed price PPAs with South Carolina small power producer QFs, based upon the avoided cost rates and contacts approved by this Commission, up to the point the initial 20 percent of South Carolina retail peak threshold prescribed by S.C. Code. Ann. § 58-41-20(F)(2) is met. For the avoidance of doubt, this requirement includes offering 10-year fixed price PPAs to QFs up to 2 MW eligible for the Standard Offer as well as large QFs up to 80 MW eligible for Duke's Large QF Form PPA. Johnson Development Witness Chilton notes that prior to Act 62's enactment Duke offered larger QFs negotiated fixed-price PPAs for a term of only five years. (Tr. Vol. 1, p. 334.10.) The Commission understands from Witness Brown's testimony that Duke's policy of limiting larger QF PURPA contracts to five year terms was consistent with the maximum PURPA contract terms that is allowed by law in North Carolina. (Tr. Vol. 2, p. 621.25.) Consistent with S.C. Code Ann. § 58-41-20(F)(1), Duke Witness Brown's testimony during the hearing indicates that Duke fully understands the requirements of Act 62 to offer all South Carolina small power producer QFs commercially reasonable fixed price PURPA PPAs, as approved by the Commission, "for a duration of ten years" up to the 20 percent of South Carolina retail peak threshold. (Tr. Vol. 2, p. 688-689.)

The more controversial issue under S.C. Code Ann. § 58-41-20(F)(1) and (F)(2) is whether the Commission should, in its discretion, approve a fixed price PPA in this proceeding with a duration longer than 10 years. In balancing the interest of the QF industry and the risks to ratepayers of longer term fixed price contracts, the General Assembly expressly prescribed in Act 62 that any such longer-term fixed price PPA option approved by the Commission, "must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including but not limited to, a reduction in the contract price relative to the ten year avoided cost." *See* S.C. Code Ann. § 58-41-20(F)(1). The General Assembly further directed that the any such longer term PPA option "shall be based on the avoided cost rates and methodologies as determined by the commission" in these proceedings, and granted the Commission the authority to "determine any other necessary terms and conditions deemed to be in the best interest of the ratepayers." *Id.*

The Commission concludes that no intervening party to these proceedings elected to put forward a proposal that conforms to the mandates of S.C. Code Ann. § 58-41-20(F)(1) until the filing of proposed orders, as recently allowed by the Commission's Order No. 2019-128-H. Act 62 was passed into law on May 16, 2019, almost 6 months ago, establishing the opportunity for intervenors to put forward PPA proposals that would meet the statutory conditions to justify Commission approval of an optional longer-term fixed price PPA exceeding 10 years. Both Johnson Development and SCSBA filed direct testimony on September 11, 2019, and subsequently filed surrebuttal testimony on October 11, 2019, with Johnson Development Witness Chilton recognizing in both direct and rebuttal testimony that "appropriate statutory conditions" were required for the Commission to approve an alternative longer-term fixed price PPA proposal. At the hearing, Witness Chilton expressly declined to offer a proposal on behalf of Johnson Development when asked by the Commission, while SCSBA Witness Levitas put forward multiple high level conceptual proposals of potential longer-term fixed price PPA structures. (Tr. Vol. 2, p. 355, 358-360.) Johnson Development and SCSBA have not explained why they elected not to timely present proposed "additional terms, conditions, and/or rate structures" for consideration by Duke, ORS, and other customer intervenors who will be obligated to pay for the QF power contracted for by Duke under the avoided cost rates and fixed price PPAs approved by the Commission in these proceedings.

Commission Order No. 2019-128-H established that it would not be appropriate for Johnson Development and SCSBA to offer new evidence after the hearing, but, over Duke's objection, accepted that it would be "permissible to include proposals that are <u>based on the evidence and testimony in the record of the case</u> in proposed orders." (emphasis in original). The Commission finds that Johnson Development and SCSBA have generally attempted to comply with this directive, but their proposal still effectively presents new evidence in the form of the proposed modified terms, conditions, and/or rate structures that they advocate the Commission approve as part of a longer-term fixed price PPA option.

Duke, ORS and other parties have had no opportunity to review and provide evidence to the Commission on this proposal and would be prejudiced if the Commission approved the alternative PPA proposal based upon the current record in these proceedings. The Commission also has not had the benefit of receiving ORS' and Duke's perspectives on whether the Commission should impose "other necessary terms and conditions deemed to be in the best interest of the ratepayers" as provided for in the S.C. Code. Ann. § 58-41-20(F)(1). The Commission also finds that Johnson Development's and SCSBA's proposal is deficient under the Statute as it fails to properly be based upon "a reduction in the contract price relative to the ten year avoided cost" as expressly required by S.C. Code Ann. § 58-41-20(F)(1). Because any determination by the Commission to approve contracts with a duration of longer than ten years must be predicated on specific proposals from intervenors that comply with S.C. Code Ann. § 58-41-20(F)(1) and are entered into the evidentiary record during the course of this proceeding, the Commission declines to approve the proposals from Johnson Development and SCSBA.

Even if the Commission was able to take the intervenor proposal into consideration, the evidentiary record does not support the adoption of a fixed price PPA for a term longer than 10 years at this time. First, the Commission finds that Johnson Development Witness Chilton's testimony that PURPA and Act 62 implicitly require that the Commission ensure that QFs are able to obtain "regularly-available, market-rate financing" and access to "mainstream capital" has no basis in either PURPA or the plain language of Act 62. These terms and concepts are not prescribed by PUPRA or FERC's regulations implementing PURPA. As Duke Witness Brown notes, FERC has held that the term and structure of forecasted avoided cost rates is left to the discretion of the implementing State Commission, as long as the contract term offered is "long enough to allow QFs reasonable opportunities to attract capital from potential investors." (Tr. Vol. 2, p. 621.36 *citing Windham Solar, LLC*, 157 FERC ¶ 61,134 at ¶ 8 (2016).) Similar to FERC's regulations implementing PURPA, Act 62 does not address QF financing requirements. To the contrary, and consistent with PURPA, Act 62 tasks the Commission with ensuring that avoided cost rates and terms are fully and accurately calculated, just and reasonable to ratepayers, non-discriminatory to QFs, and further requires to the Commission to strive to reduce the risk placed upon the using and consuming public. *See* S.C. Code Ann. § 58-41-20(A).

The Commission also finds that the provisions of Subsection (F)(1) described above are similarly focused on mitigating the risk of longer term fixed price contracts for consumers, and in no way direct the Commission to attempt to discern what type of financing QF owners and investors may require to invest in a QF project in South Carolina. As Witness Brown explains, PURPA largely exempts QFs from Commission oversight of their profits and business operations so that neither the Companies, the ORS, nor the Commission has any clear insight into the actual cost of a QF project or a QF developer's business, including the level of profit deemed "reasonable" to attract equity capital. (Tr. Vol. 2, p. 621.38 *citing* 18 C.F.R. § 292.602(c)(1).) Notably, despite active participation in this proceeding from the solar industry, no QF developers have elected to voluntarily inform the Commission regarding their actual costs of developing QF projects, the amount of debt they use for financing QF projects, or the return on equity required by QF investors.

Thus, in contrast to a general rate case for a regulated electrical utility where the utility's cost of debt and equity to be used for ratemaking purposes are carefully reviewed by ORS and approved by the Commission based upon the utility's actual costs, the Commission has no meaningful ability to assess the financeability of QFs under the avoided cost rates and 10-year fixed price term of PPAs required by Act 62.

Even if an appropriate proposal had been made at the appropriate time, there have been no tangible customer benefits from longer terms contracts articulated in this proceeding that would justify a longer term—at best, only speculative benefits have been articulated. As highlighted by Duke Witness Brown and discussed more extensively earlier in this Order, Duke is also continuing to offer South Carolina solar QFs the opportunity to compete for fixed price 20-year PPAs through the CPRE Program Tranche 2 competitive solicitation process. The Commission finds Witness Brown's testimony persuasive that this independently administered competitive solicitation process provides a less risky and more cost-effective way to procure new solar capacity for customers than the Commission approving future projections of avoided cost rates for periods longer than 10 years into the future. The Commission recognizes this ongoing competitive solicitation process as providing a meaningful opportunity for South Carolina QFs to compete to deliver least cost solar projects to DEC and DEP to serve customers in both South Carolina and North Carolina, while balancing promoting Act 62's directive for the Commission to encourage the development of renewable energy while striving to reduce risks to the using and consuming public.

Finally, the Commission notes the discussion of QF financeabilty in the Power Advisory Report and Power Advisory's statement that "without longer contract lengths, the solar industry would not be able to finance solar projects in South Carolina at Duke's current avoided costs because they would not be economical." *Power Advisory Report*, p. 34. However, Power Advisory offers limited information to support its conclusion, the majority of which is not information that is properly entered into the record in this proceeding for our consideration. As such, the Commission recognizes the limitation on its consideration of the information provided by Power Advisory in this regard and does not find Power Advisory's limited analysis and conclusory statements sufficiently persuasive to support a contract length longer than ten years.

In sum, the Commission has carefully reviewed this issue under the standards and requirements prescribed by the General Assembly in S.C. Code Ann. § 58-41-20(F)(1), and finds that no proposal from intervenors has been entered into evidence this proceeding that complies with the statute. Duke is required by Act 62 to offer all small power producer QFs up to 80 MW a 10-year fixed price PPA based upon the avoided cost rates and contract documents approved by the Commission in this Order. South Carolina solar QFs may also elect to compete in the now-open CPRE Program Tranche 2 for a 20-year fixed price PPA if the QF is the most cost-effective option for customers. The Commission also notes that S.C. Code Ann. § 58-41-20(A) provides electrical utilities and small power producers the right to mutually agree to enter into PPAs with terms that differ from the commission approved form(s); however, those terms will not be dictated as just and reasonable and mandatory for all QFs in these proceedings. JDA and SCSBA members are free to bring their proposals as part of those PPA negotiations, and they may also timely bring forward proposals that meet the subsection (F)(1) requirements in future avoided costs/PURPA implementation proceedings initiated by the Commission under S.C. Code Ann. § 58-41-20(A).

VI. ORDERING PARAGRAPHS

NOW, THEREFORE, IT IS HEREBY ORDERED THAT:

1. Based upon the Joint Application, the testimony, and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission hereby adopts each and every finding of fact enumerated herein. The Commission's conclusions of law are fully stated above.
2. Any motions not expressly ruled upon herein are denied.
3. Within 15 days of the date of this Order, DEC and DEP shall each file final avoided cost rates, Standard Offer tariffs, Schedule PP PPAs and terms and conditions, form contract power purchase agreements for Large QFs, and Notice of Commitment to Sell forms consistent with the requirements of this Order.
4. The Standard Offer tariffs shall become effective November 30, 2018, and shall remain in effect until the date that the Companies' next file updated avoided cost rates with the Commission.

5. On or before November 18, 2019, Duke shall file proposed guidelines for QFs to become "controlled solar generators" and thereby avoid the SISC, as contemplated by the SISC Stipulation approved herein.

BY ORDER OF THE COMMISSION:

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Comer H. Randall, Chairman

____
Justin T. Williams, Vice Chairman

(SEAL)